COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Board

In the Matter of the Petition of Berkshire Power Development, Inc. for Approval to Construct a Bulk Generating Facility and Ancillary Facilities

EFSB 95-1

FINAL DECISION

Robert P. Rasmussen
Hearing Officer
June 19, 1996

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EXHIBITS:

LIST OF ABBREVIATIONS

Abbreviation	Explanation
ABB EV	ABB Energy Ventures, Inc.
ABB O&M	ABB Operations and Maintenance Department
ABB Power Generation	ABB Power Generation, Inc.
ACS	Advanced Cycle System
Actual peak, weather-normalized	The highest, resconstituted, weather-normalized 1994 summer peak load
AFBC	Atmospheric fluidized bed coal facility
AFBC alternative	The AFBC used in the Company's alternative technology analysis
Agawam	Town of Agawam
Agawam municipal system	Agawam municipal water supply system
Attorney General	Attorney General v. Energy Facilities Siting Board, 419 Mass. 1003 (1995)
average peak	an average of the weather-normalized peak load summer peak candidate days
BACT	Best available control technology
Bay State	Bay State Gas Company
Berkshire-in case	A detailed economic analysis based on NEPOOL dispatch practices for the period 1999 through 2018, which included the dispatch of the proposed facility
Berkshire-out case	A detailed economic analysis based on NEPOOL dispatch practices for the period 1999 through 2018, which did not include the dispatch of the proposed facility
bmt	Billion metric tons
Bondi's Island	City of Springfield's Wastewater Treatment Facility at Bondi's Island
Box turtle	The eastern box turtle
BPD	Berkshire Power Development, Inc.
Btu/kwh	British thermal units per kilowatt hour
B&V	Black and Veatch Construction, Inc.
CAAA	Federal Clean Air Act Amendments of 1990

CCBA	Concerned Citizens & Businesses of Agawam
CCBA Brief	CCBA's initial brief
CELT	Capacity, Energy, Loads and Transmission (yearly reports prepared by NEPOOL)
Chez Josef	Chez Josef, Inc.
<u>City of New Bedford</u>	<u>City of New Bedford v. Energy Facilities Siting Council</u>, 413 Mass. 482 (1992)
CMF	C.M.F. Engineering, Inc.
CMP	Central Maine Power
CO	Carbon monoxide
CO_2	Carbon dioxide
Cobble Mountain	Cobble Mountain Reservoir in Blandford
Company	Berkshire Power Development, Inc.
Company Brief	BPD's initial brief
Company's Massachusetts base need scenario	A comparison of the 1994 Massachusetts normalized 2.5 percent forecast, adjusted by the low DSM scenario, with the low supply forecast
Company Reply Brief	BPD's reply brief
Company's base need scenario	A comparison of the 1994 normalized 2.5 percent forecast, adjusted by the low DSM scenario, with the low supply forecast
Connecticut River option	The alternative water supply option that would use water drawn from the Connecticut River in Agawam
Country Estates	Country Estates Nursing Home, Inc.
Country Estates Brief	Country Estates's reply brief
Court	Supreme Judicial Court
CRWC	Connecticut River Watershed Council, Inc.
CSC	Cogeneration Services Corporation
dBA	Decibel
DCR	Debt coverage ratios
DEIR	Draft Environmental Impact Report

Department	Department of Public Utilities
DFW	Division of Fisheries and Wildlife
DOMAC	Distrigas of Massachusetts
$/kWh	Dollars per kilowatt-hour
DSM	Demand side management
Eastern Edison	Eastern Edison Company
EMF	Electric and magnetic fields
EMI	Energy Management, Inc.
EPA	The United States Environmental Protection Agency
EPC	Engineering, procurement, and construction
EPC turnkey contract	Turnkey construction contract
EPRI	Electric Power Research Institute
ERCs	Emission reduction credits
FERC	Federal Energy Regulatory Commission
FEV	The Fairfield Energy Venture
Firm gas supply	The assumption used in analyzing fuel costs that gas supply from the wellhead to the proposed facility will be firm
Fuel cell	Phosphoric acid fuel cell
GEP	Good Engineering Practice
Groundwater well option	The alternative water supply option that would use water drawn from wells
GT-24	The ABB GT-24 ACS Combined Turbine Generator
GTCC	Gas-fired combined cycle unit
GTCC alternative	A GTCC with oil backup used in the Company's alernative technology analysis
Higher heat rate	An assumed approximate heat rate of 7,000 Btu/kwh used in the Company's analysis of the costs and operating characteristics of the proposed facility
HQ II	Hydro-Quebec Phase II
HRSG	Heat recovery steam generator
IGCC	Integrated coal gasification combined cycle unit

IGCC alternative	The IGCC used in the Company's alternative technology analysis
Industrial Park	Shoemaker Industrial Park
IPP	Independent power producer
IRM	Integrated Resource Management
Iroquois	Iroquois Gas Pipeline Company
kV	Kilovolt
L_{90}	The level of noise that is exceeded 90 percent of the time
LAER	Lowest Achievable Emission Rate
The Lawlors	Cynthia A. and Frank J. Lawlor
lbs/MMBtu	Pounds per million British thermal units
L_{dn}	EPA's recommendation of a maximum day-night noise level of 55 dBA in residential areas
LOS	Levels of service -- a measure of the efficiency of traffic operations at a given location
lower heat rate	The actual predicted heat rate of the proposed facility used in the Company's analysis of the costs and operating characteristics of the proposed facility
MAAQS	Massachusetts ambient air quality standards
MCZM	Massachusetts Coastal Zone Management
MDEP	Massachusetts Department of Environmental Protection
MECo	Massachusetts Electric Company
mG	Milligauss
mgd	Million gallons per day
MMWEC	Massachusetts Municipal Wholesale Electric Company
MSW	Municipal solid waste facility
MW	Megawatt
NAAQS	National ambient air quality standards
NEC	Nantucket Electric Company
NEES	New England Electric System
NEPOOL	New England Power Pool

1993 CELT dispatch scenario	The Berkshire-out and Berkshire-in analyses based on the 1993 CELT forecast, higher heat rate and firm gas supply
1993 CELT forecast	Regional load forecast derived from NEPOOL's 1993 CELT report reference forecasts of unadjusted summer and winter peak loads
1993 NEPOOL Massachusetts forecast	Massachusetts load forecast based on NEPOOL's Massachusetts-specific forecasts of summer and winter peak load for 1993 included in the 1993 NEPOOL report, "Energy and Peak Load Forecast Exhibits, Massachusetts"
1993 TAG	1993 EPRI TAG Report
1994 CELT dispatch scenario	The Berkshire-out and Berkshire-in analyses based on the 1994 final CELT forecast, higher heat rate and firm gas supply
1994 initial NEPOOL Massachusetts forecast	Massachusetts summer and winter peak demand forecast developed by prorating the 1994 final NEPOOL Massachusetts forecast by multiplying the 1994 final NEPOOL Massachusetts forecast by the ratio of the 1994 initial CELT forecast to the 1994 final CELT forecast
1994 final NEPOOL Massachusetts forecast	Massachusetts load forecast based on NEPOOL's Massachusetts-specific forecasts of summer and winter peak load for 1994 included in the 1994 NEPOOL report, "Energy and Peak Load Forecast Exhibits, Massachusetts"
1994 final CELT forecast	Regional load forecast derived from NEPOOL's final 1994 CELT report reference forecasts of unadjusted summer and winter peak loads
1994 GTF	The June 1994 Generation Task Force Assumption Book
1994 initial CELT forecast	Regional load forecast derived from NEPOOL's initial 1994 CELT report reference forecasts of unadjusted summer and winter peak loads
1994 Massachusetts normalized 2.5 percent forecast	Massachusetts load forecast derived by escalating the 1994 summer and winter Massachusetts-specific peaks, weather-normalized, by 2.5 percent per year
1994 normalized CELT forecast	Regional load forecast derived by escalating the 1994 summer highest weather-normalized peak by the growth rates embodied in the 1994 final CELT forecast

1994 normalized 2.5 percent forecast	Regional load forecast derived by escalating the 1994 summer and winter actual peaks, weather-normalized, by 2.5 percent per year
1995 CELT forecast	Regional load forecast derived from NEPOOL's 1995 CELT report reference forecasts of unadjusted summer and winter peak loads
1995 NEPOOL Massachusetts forecast	Massachusetts summer and winter peak demand forecast developed by prorating the 1994 final NEPOOL Massachusetts forecast by multiplying the 1994 final NEPOOL Massachusetts forecast by the ratio of the 1995 CELT forecast to the 1994 final CELT forecast
NHESP	Natural Heritage and Endangered Species Program
NOx	Nitrogen oxides
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
Order of Conditions	Agawam Conservation Commission's Order of Conditions
PASNY	Power Authority of the State of New York
Pb	Lead
PC	Pulverized coal facility
PC alternative	The PC used in the Company's alernative technology analysis
PDC	Power Development Company
Pendulum	Pendulum Gas Services
PFBC	Pressurized fluidized bed coal facility
PFBC alternative	The PFBC used in the Company's alernative technology analysis
PM-10	Particulates
<u>Point of Pines</u>	<u>Point of Pines Beach Association v. Energy Facilities Siting Board</u>, 419

Mass. 281 (1995)

PPA	Power purchase agreement
PSD	Prevention of significant deterioration
PURPA	Public Utility Regulatory Policies Act of 1978, 16 U.S.C. §§ 796, 824a-3
QF	Qualifying facility
RFP	Request for Proposals
ROW	Right-of-way
SACTI	Seasonal/Annual Cooling Tower Plume Impact model
SCBI	Springfield Corrugated Box, Inc.
SILs	Significant impact levels
Siting Board	Energy Facilities Siting Board
Siting Council	Energy Facilities Siting Council
SS-RFP	Site Selection RFP
Standard Uniform	Standard Uniform Services
SO_2	Sulfur dioxide
SOx	Sulfur oxides
TAG	EPRI Technical Assessment Guide
TEC	Taunton Energy Center
TELs	Threshold effects exposure limits
Tennessee	Tennessee Gas Pipeline Company
Town	Town of Agawam
tpy	Tons per year
Trout Unlimited	Trout Unlimited, Pioneer Valley Chapter #276
Updated 1994 CELT dispatch scenario	The Berkshire-out and Berkshire-in analyses based on the 1994 final CELT forecast, lower heat rate and firm gas supply
USGen	U.S. Generating Company
VOCs	Volatile organic compounds
WMECo	Western Massachusetts Electric Company
Wright	Wright, New York

Wright gas supply	The Company anticipated firm gas transportation contract from Wright, New York to the proposed project
ZBA	Zoning Board of Appeals

The Energy Facilities Siting Board ("Siting Board") hereby approves subject to conditions the petition of Berkshire Power Development, Inc. to construct a 252-megawatt, natural gas-fired generating facility and ancillary facilities in Agawam, Massachusetts.

I. INTRODUCTION

A. Summary of the Proposed Project and Facilities

Berkshire Power Development, Inc. ("BPD" or "Company") has proposed to construct a nominal net 252-megawatt ("MW") natural gas-fired, combined-cycle independent power plant on an approximately 40-acre undeveloped parcel of land located at the Shoemaker Industrial Park in the Town of Agawam, Massachusetts ("Town" or "Agawam"), which would commence commercial operation in 1999 (Exh. BP-1A at 1-1, 2-1). The parcel is currently owned by Edward Zielinski and is used as a private runway for small aircraft with smaller portions used for vegetable production (id. at 2-3; Exh. HO-S-7(red.)(att.) at 2).

The proposed facility would be powered with natural gas delivered through a new, high-pressure pipeline interconnection with the nearby Tennessee Gas Pipeline ("Tennessee") facility, using low-sulfur (0.05 percent) distillate oil as a back-up fuel (Exh. BP-1A at 2-2, 2-5). 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 (id. at 4-22).

The electricity generated by the proposed facility would be transmitted via an approximately 500-foot long, 115 kilovolt ("kV") transmission line from the proposed facility to existing 115 kV Western Massachusetts Electric Company ("WMECo") transmission lines which cross the northern portion of BPD's Agawam site (id. at 2-5).

The major components of the proposed project include: (1) a GT-24 Advanced Cycle System ("ACS") Combustion Turbine Generator, which will generate approximately 165 MW of electricity; (2) a heat recovery steam generator ("HRSG"); (3) a steam turbine generator which will produce an additional 85 MW of electricity; (4) a selective catalytic reduction system for Nitrogen Oxides ("NOx") control; (5) a carbon monoxide ("CO") catalyst; (6) a cooling tower; and (7) a 125-foot exhaust stack (id. at 2-1, 2-9, 7-22; Exhs. HO-E-26; BP-FS-2, at 2-31, 2-32). Additional components include an administration building, a 970,000-gallon fuel storage tank, a 12,000-gallon ammonia storage tank, water tanks and electrical and water treatment equipment (Exhs. BP-1A at 2-9; HO-V-17; HO-E-72). The Company indicated that the most prominent structures associated with the proposed project would be the generation building, the exhaust stack and the cooling tower (Exh. BP-1B at 7-94). The remaining facilities include a variety of smaller buildings and miscellaneous storage tanks, which are less prominent and of an industrial appearance (id.).

The Company's proposed site is located in an industrially zoned area of Agawam (Exh BP-1A at 1-1, 2-3). The northern portion of the proposed site is primarily an open, grassed field and the southern portion is heavily wooded (id. at 2-3). The proposed site is abutted on the north and northeast by wooded and undeveloped, with the exception of two existing 115 kV transmission lines, property owned by WMECo; on the southeast by industrially zoned properties on Industrial Lane and a construction company on Shoemaker Lane; on the south by Shoemaker Lane; on the southwest and west by developed and undeveloped industrially zoned properties; and to the northwest by a lumber company (id. at 2-3 to 2-4).

The proposed project would cost approximately $176 million in 1995 dollars (Exh. HO-RR-6).

The proposed project is being developed by BPD, which is a joint venture of Power Development Company ("PDC"), ABB Energy Ventures, Inc. ("ABB EV"), and Cogeneration Services Corporation ("CSC") (id. at 1-5; Exh. CCBA-RR-2). BPD was formed on May 4, 1995 to manage the development process, execute necessary contracts, and initially hold the permits issued to the project (Exh. CCBA-RR-2). PDC is a privately held company, incorporated in Delaware on April 7, 1993, that develops electrical/energy related projects (Exhs. HO-V-3; HO-V-22). CSC serves the role of ensuring that the proposed project is technically sound, meets all deadlines and stays within budget (Exh. BP-1A at 1-6). CSC also provides development management, community relations and permitting oversight (id.). BPD will establish either a limited partnership (Berkshire Power L.P.) or a limited liability corporation (Berkshire Power LLC) to take ownership of the project sometime prior to financial closing, and will transfer all contracts, obligations and permits acquired during the development process to this new entity (Exh. CCBA-RR-2).

B. Jurisdiction

BPD's petition to construct a bulk generating facility and ancillary facilities 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.

As an independent power plant with a design capacity of approximately 252 MW, BPD'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, BPD's proposals to construct a transmission line 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 June 20, 1995, BPD filed with the Siting Board[1] its proposal to construct a nominal

[1] 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.

252 MW natural gas-fired independent power plant and ancillary facilities in the Town of Agawam, Massachusetts. The Siting Board docketed this petition as EFSB 95-1. On August 17, 1995, the Siting Board conducted a public hearing in Agawam, and on August 30, 1995, the Siting Board conducted a public hearing in Southwick, Massachusetts. In accordance with the direction of the Hearing Officer, the Company provided notice of the public hearings and adjudication.

Petitions to intervene were filed by Chez Josef, Inc. ("Chez Josef"); Springfield Corrugated Box, Inc. ("SCBI"); Concerned Citizens & Businesses of Agawam ("CCBA"); Bay State Gas Company ("Bay State");[2] Cynthia A. and Frank J. Lawlor ("the Lawlors"); Country Estates Nursing Home, Inc. ("Country Estates"); WMECo; Standard Uniform Services ("Standard Uniform"); and U.S. Generating Company ("USGen").[3] Petitions to participate as an interested person were filed by the Connecticut River Watershed Council, Inc. ("CRWC"); Energy Management, Inc. ("EMI"); C.M.F. Engineering, Inc.; and Trout Unlimited, Pioneer Valley Chapter #276 ("Trout Unlimited").

The Hearing Officer allowed the petitions to intervene of Chez Josef,[4] CCBA and WMECo as to any and all matters associated with this proceeding, and the petitions to intervene of SCBI, the Lawlors, Country Estates, and Standard Uniform as to any and all matters associated with environmental impacts and cost. See Hearing Officer Procedural Order, October 11, 1995, at 7-8. The Hearing Officer also allowed the petitions to participate as an interested person of CRWC, EMI, Trout Unlimited, Bay State and USGen. Id. at 8-9; Hearing Officer Procedural Order, October 27, 1995 at 2.

The Siting Board conducted thirteen days of evidentiary hearings commencing January 8, 1996 and ending February 12, 1996. BPD presented eight witnesses: Charles

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[2] Bay State amended its petition to intervene to a petition to participate as an interested person at the Procedural Conference on September 28, 1995.

[3] USGen amended its petition to intervene to a petition to participate as an interested person on October 17, 1995.

[4] Chez Josef withdrew its petition for intervenor status on November 17, 1995.

Stankiewicz, vice president of steam turbines and industrial gas turbines with ABB Power Generation, Inc., who testified regarding design and operating characteristics of the generator turbine; Douglas Corbett, project fuel manager for PDC, who testified regarding fuel procurement strategies; David N. Keast, a consultant in acoustics, who testified regarding noise issues; Frederick M. Sellars, senior program director and manager of the air quality consulting and engineering group at Earth Tech, who testified regarding environmental issues and site selection; Dale T. Raczynski, senior program director for Earth Tech, who testified regarding air quality; Kenneth Roberts, director of development for PDC, who testified regarding the construction and operation of the proposed project and general project matters; Roger M. Cotte, a partner and managing director of R.W. Beck, who testified regarding financing of the proposed project; and Robert Graham, a senior associate with La Capra Associates, who testified regarding the need for the proposed project and alternative technology issues. CCBA sponsored the testimony of one rebuttal witness, Amy Jean Ringuette, who testified regarding issues related to the habitat of the Eastern box turtle in the vicinity of the site.

The Company filed its brief ("Company Brief") and CCBA filed its brief ("CCBA Brief") on March 6, 1996. Country Estates filed a rebuttal brief ("Country Estates Brief") on March 14, 1996. The Company filed its reply brief ("Company Reply Brief") on March 15, 1996.

The Hearing Officer entered 502 exhibits into the record, consisting primarily of information and record request responses. BPD entered 63 exhibits into the record. CCBA entered 31 exhibits into the record. The Lawlors entered 2 exhibits into the record. Trout Unlimited entered 9 exhibits into the record.

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. Cabot Power Corporation, 2 DOMSB 241, 253 (1994) ("Cabot

Decision"); Altresco Lynn, Inc., 2 DOMSB 1, 17 (1993) ("Altresco Lynn 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. Cabot Decision, 2 DOMSB at 253; Altresco Lynn Decision, 2 DOMSB at 18; 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. Cabot Decision, 2 DOMSB at 253; Altresco Lynn Decision, 2 DOMSB at 18; 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. Cabot Decision, 2 DOMSB at 253; Altresco Lynn Decision, EFSB 91-102, at 11; 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. Eastern Energy Corporation (on remand), 1 DOMSB 213, 383-397 (1993) ("EEC (remand) Decision"); 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)." Id., 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 its EEC (remand) Decision, 1 DOMSB at 421-423.

With respect to the issue of regional need vs. 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 yet 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. Cabot Decision, 2 DOMSB at 241, 258, 291-292, 319; Altresco Lynn Decision, 2 DOMSB at 26, 61, 92; Altresco-Pittsfield, Inc., 17 DOMSC 351, 360-369 (1988) ("Altresco-Pittsfield Decision"); 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. Middleborough Gas and Electric Department, 17 DOMSC 197, 216-219 (1988); Boston Edison Company, 13 DOMSC 63, 70-73 (1985) ("1985 BECo Decision"); 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. Cabot Decision, 2 DOMSB at 258; Altresco Lynn Decision, 2 DOMSB at 19; 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 our 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. Cabot Decision, 2 DOMSB at 292-300; Altresco Lynn Decision, 2 DOMSB at 61-68; 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,[5] but also the consideration of whether proposals to construct energy facilities within the Commonwealth are needed to meet New England's energy needs. Cabot Decision, 2 DOMSB at 259, 291-292; Altresco Lynn Decision, 2 DOMSB at 19, 61; 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. Cabot Decision, 2 DOMSB at 296-300; Altresco Lynn Decision, 2 DOMSB at 65-68; EEC (remand) Decision, 1 DOMSB at 417-418. However, in response to the Court's reminder in City of New Bedford that our 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. 1 DOMSB at 418. See also, Cabot

[5] See Hingham Municipal Lighting Plant, 14 DOMSC 7 (1985); 1985 BECo Decision, 13 DOMSC at 70-73.

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")[6] 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.[7]

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6 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 byproduct in addition to its electric sales.

7 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. Point of Pines Beach Association v. Energy Facilities Siting Board, 419 Mass. 281, 285-286 (1995) ("Point of Pines"). Referencing its decision in Point of Pines, the Court vacated a final decision of the Siting Board for this same reason in Attorney General v. Energy Facilities Siting Board, 419 Mass. 1003

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. Cabot Decision, 2 DOMSB at 259; Altresco Lynn Decision, 2 DOMSB at 27; 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 capacity, economic and environmental purposes.

2. Capacity 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 Cabot Decision, 2 DOMSB at 289-290; Altresco Lynn Decision, 2 DOMSB at 58-59; 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 1998/1999 to 2002 time period.

(1995) ("Attorney General").

a. New England

BPD asserted that there is a need for at least 252 MW of additional energy resources in New England beginning in the year 1999 and beyond (Company Brief at 28). In support, the Company presented a series of forecasts of demand and supply for the region, based primarily on the 1993, 1994 and 1995 forecasts and other data published by NEPOOL. The Company stated that it compared its demand and supply forecasts to produce a series of need forecasts (Exh. BP-RG-1, at 13-14).

In the following sections, the Siting Board reviews the Company's demand forecasts, including its demand forecast methods and estimates of demand side management ("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

BPD presented a range of forecasts of unadjusted summer and winter peak load and DSM savings, derived primarily from information contained in the 1993, 1994 and 1995 Capacity, Energy, Loads and Transmission ("CELT") reports, published by NEPOOL (Exhs. BP-1A at 3-5; BP-RG-1, at 2-5).[8] The Company presented six forecasts of unadjusted summer peak load and five forecasts of unadjusted winter peak load (Exhs. BP-RG-1, atts. 3, 4; HO-RR-29). To develop forecasts of adjusted load, the Company combined these demand forecasts with (1) the 1995 CELT report forecast of NUG netted from load, and (2) three

[8] 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, 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 (Exhs. HO-RN-1, atts. a, b, i; HO-RN-4, att. a; Tr. 6, at 66-67).

forecasts of DSM savings based on the 1995 CELT report forecast of DSM savings (Exhs. BP-RG-1, atts. 3,4; HO-RR-29). Overall, the Company provided sixteen forecasts of adjusted summer peak load and thirteen forecasts of adjusted winter peak load (Exhs. BP-RG-1, atts. 3, 4; HO-RR-29).

(1) Demand Forecast Methods

The Company stated that three summer and three winter unadjusted peak load forecasts were derived directly from the NEPOOL CELT report reference forecasts of unadjusted load for summer and winter peak for the years: (1) 1993 ("1993 CELT forecast"); (2) 1994 ("1994 final CELT forecast"); and (3) 1995 ("1995 CELT forecast") (Exhs. BP-1A, at 3-9, 3-13; BP-RG-1, at 2-5). The Company stated that it also derived summer and winter peak load forecasts directly from an initial CELT reference forecast prepared in 1994 ("1994 initial CELT forecast") (Exh. BP-1A at 3-12).[9]

BPD stated that it developed two further load forecasts based on actual peak loads experienced in 1994 (Exhs. BP-1A, at 3-10 to 3-12; HO-RR-29).[10] The first of these forecasts

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[9] The Company indicated that, prior to issuing the 1994 CELT report, NEPOOL produced an initial load forecast which was higher than the forecast included in that CELT report (Exh. BP-1A at 3-12 to 3-13). The Company asserted that the NEPOOL Policy Planning Committee revised this 1994 initial CELT forecast downward in response to concerns that the forecast was higher than the sum of the individual member utilities' forecasts (Exh. HO-RN-4, at 2, att.(a)). The 1994 final CELT forecast was included in the 1994 CELT report (id.; Exh. HO-RN-1, att. b).

[10] The Company considered three different "actual" summer peak loads for 1994: (1) the highest, reconstituted summer peak load which was weather-normalized amounting to 20,534 MW ("actual peak, weather-normalized"); (2) the highest weather-normalized peak load of 21,138 MW; and (3) an average of the weather-normalized peak load ("average peak") based on 32 summer peak candidate days amounting to 20,200 MW (Exhs. HO-RN-1, att. K at 11; BP-1A at 3-11; Tr. 6 at 45-46).

With respect to winter peak load, the Company stated that: (1) the actual peak, weather normalized was 19,093 MW; (2) the highest weather normalized peak was 19,869 MW; and (3) the average peak, based on 22 peak candidate days, was 19,250 MW (Exh. HO-RN-1, att. k at 11).

escalates the 1994 summer highest weather-normalized peak of 21,138 MW by the growth rates predicted in the 1994 final CELT forecast ("1994 normalized CELT forecast") (Exh. BP-1A at 3-10 to 3-12). The second forecast, characterized by the Company as the most likely forecast, escalates the 1994 summer and winter actual peaks, weather-normalized by 2.5 percent per year ("1994 normalized 2.5 percent forecast") (Exh. HO-RR-29).[11] The Company also provided summer and winter forecasts starting from the average peaks (Exh. HO-RR-29). Inasmuch as these forecasts were provided after the close of hearings and the Company discusses only the 1994 normalized 2.5 percent forecast in its Brief (see, Company Brief at 38-39), the Siting Board does not consider the forecast based on average peaks in its review of regional need.

The Company stated that all its forecasts were adjusted to incorporate the addition of Nantucket Electric Company ("NEC") load to NEPOOL beginning in 1997 (Exhs. BP-1A at 3-7, 3-9 to 3-10; HO-RN-2).

The Company asserted that the 1994 normalized 2.5 percent forecast represents a reasonable base case demand forecast because it reflects the current consensus economic

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The Company noted that NEPOOL reports the average peak as the seasonal peak load (Tr. 6, at 45-46). However, Mr. Graham stated that it was not appropriate to determine a peak day by the average of candidate peak days, because the method of selecting peak days to average would determine the results (id. at 47-48). He added that by choosing to include lower temperature-humidity days in the average, NEPOOL lowered the average peak (id. at 48-49). The Company indicated that the 1992 summer peak reported by NEPOOL was based on the reconstituted peak of one day and that the 1993 winter peak reported by NEPOOL was an average peak of 12 days (Exh. HO-RR-43, att. a at 11).

11 The Company stated that, because the actual peak, weather-normalized and highest weather-normalized peak reflect the effects of DSM and NUG netted from load, it was necessary to estimate the unadjusted load for 1994 by adding the amounts of DSM and NUG netted from load in the 1994 CELT report to the 1994 weather-normalized peak (Exhs. BP-1A at 3-11; HO-RR-29, at 1, n.1). The Company also stated that (1) unadjusted load was then escalated annually, and (2) projected DSM and NUG netted from load were then subtracted to obtain a forecast of adjusted load (Exhs. BP-1A at 3-11; HO-RR-29, at 1, n.1).

growth outlook for the region and the historic linkage between economic growth and load growth in the region (Exh. HO-RR-29; Company Brief at 31-32). In addition, the Company asserted that the 1993 CELT forecast and the 1994 normalized CELT forecast represent reasonable high case demand forecasts and that the 1994 initial CELT forecast represents a reasonable low case demand forecast (Company Brief at 31-32). The Company further asserted that the 1994 final CELT forecast and the 1995 CELT forecast are based on inappropriate assessments of regional load growth and that these forecasts therefore should not be given any weight in the Siting Board's overall assessment of regional need (id. at 32, 37). Although the Company indicated its preference for the methods used in the 1993 CELT forecast, the Company acknowledged that the 1993 forecast is based on dated information (Tr. 6, at 6).

In support of its assertions, the Company stated that (1) the long-run forecasting model[12] used to develop the 1994 and 1995 CELT forecasts incorporated questionable changes in assumptions, and (2) the 1994 and 1995 CELT forecasts underforecast actual summer peak loads (Exhs. BP-1A at 3-16; BP-RG-1, at 4; HO-RN-4; Company Brief at 32-37). With respect to NEPOOL's long-run forecasting model, BPD noted that the 1993 CELT forecast was produced using the same long-run modeling assumptions as the 1992 CELT forecast, a forecast the Siting Board has accepted in a number of previous proceedings (Exh. BP-1A at 3-10). BPD claimed that in 1994, NEPOOL made a number of unjustified changes to the methods used in the long-run forecasting model which were designed to produce an unreasonably low forecast, including adjustments to: (1) air conditioning penetration rates; (2) the commercial productivity variable;[13] and (3) the forecast of economic growth[14]

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[12] BPD explained that, in developing demand forecasts, NEPOOL: (1) produces a short-term forecast for the first two years of the forecast period using a set of econometric models; (2) produces a long-term forecast starting in the fifth year of the forecast period based on a set of end-use models; and (3) blends the results of the short-term and long-term forecasts for the third and forth years of the forecast period (Exh. BP-RG-1, at 3).

[13] BPD explained that the commercial productivity variable, which is an employment-based variable adjusted for projected changes in commercial labor productivity, is the major

(Exh. HO-RN-4; Company Brief at 32).

BPD indicated that the changes in the commercial productivity variable and the forecast of economic growth were reflected in the 1994 initial CELT forecast, while the changes in air conditioning penetration rates were made between the 1994 initial and final CELT forecasts (Exhs. BP-RG-1, at 3; BP-1A at 3-12 to 3-13). BPD stated that since NEPOOL did not update its long-run forecast for the 1995 CELT forecast,[15] the 1995 CELT forecast also reflects all three changed assumptions (Exh. BP-RG-1, at 3). The Company indicated that NEPOOL considered the change in air conditioning penetrations to have the greatest impact on summer peak load (Company Brief at 33, citing, HO-RN-1).[16] BPD explained that the 1993 CELT forecast and 1994 initial CELT forecast assume that air conditioning penetrations will increase over time, consistent with growth in real personal income, but that the 1994 final and 1995 CELT forecasts assume that (1) residential air conditioning penetration would increase slightly from 1993 to 1994 and then remain constant over the forecast period, and (2) commercial new

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driver of the commercial sales forecast (Exh. HO-RN-4). BPD indicated that beginning in 1994, NEPOOL used a partial productivity adjustment rather than the full productivity adjustment used in previous years (id.). The Company maintained that this reduction was unjustified given that both employment and the partially adjusted commercial activity driver have grown at a slower rate than commercial electricity sales over the past decade (id., att. D).

14 BPD stated that the economic forecast underlying the 1994 and 1995 CELT forecasts is overly conservative in that actual growth in Gross State Product, real personal income and employment have generally been greater than NEPOOL's projections (Exh. HO-RN-4).

15 BPD explained that NEPOOL prepared a new short-term forecast for the years 1995 and 1996, and combined this updated short term forecast with the long-term forecast from the 1994 final CELT forecast (Exh. BP-RG-1, at 3).

16 The Company stated that the NEPOOL load forecasting committee "decided to lower projected penetration rates of residential and commercial air conditioning to reflect more closely current company expectations of marketplace conditions" (Tr. 6, at 12-13). The Company was unable to provide commercial air conditioning penetration forecasts for the major Massachusetts electric utilities (Exh. HO-RR-25).

construction air conditioning penetration would decline from 1993 to 1994 and then remain constant over the forecast period (Exh. HO-RN-4, at 2).[17] The Company asserted that these assumptions were unwarranted based on: (1) 1994 and 1995 summer peak load data; (2) press reports of high rates of air conditioner purchases; and (3) NEPOOL's own statements regarding "an increasing dominance of commercial and residential air conditioning load" during summer peak periods (id. at 2-3; Tr. 6, at 15).[18]

The Company stated that NEPOOL summer peak loads are largely driven by air conditioning load, and that if air conditioning penetrations increase, the summer peak loads would be significantly higher than those forecast in the 1994 final CELT and 1995 CELT reports (Exhs. HO-RN-4, at 3; BP-1A, att. 3-5).[19] The Company asserted that the 1994 initial CELT forecast, which does not incorporate the new air conditioning penetration rates, avoids a significant weakness in the 1994 final and 1995 CELT forecasts (Exhs. BP-1A at 3-12; BP-RG-1, at 3).

The Company also asserted that both the 1994 final CELT forecast and 1995 CELT forecast underforecast actual summer peak loads in the short term and medium term (Exhs. BP-1A at 3-16; BP-RG-1, at 4; Company Brief at 37). BPD stated that the 1994 summer highest weather-normalized peak exceeded the 1994 final CELT forecast's projections of summer peak through 1999 and the 1995 CELT forecast's projections of summer peak through 1998 (Exhs.

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17 The Company indicated that the 1994 final CELT forecast assumes that air conditioning penetration in new Massachusetts office buildings, restaurants, retail buildings and warehouses would decline by 25 percent from 1993 to 1994 and then remain constant over the forecast period (Exh. HO-RN-4, at 2, att. c).

18 The Company noted that, in larger commercial buildings, electric air conditioning may face some competition with gas air conditioning but that gas air conditioning would not likely be installed in smaller commercial or residential buildings (Tr. 6, at 12-13).

19 The Company also provided an assessment of air conditioning penetration trends using a time series regression analysis of air conditioning penetration on real personal income (Exh. HO-RN-44). The Company stated that this assessment demonstrates that air conditioning penetration is likely to be higher than NEPOOL's forecast over the long term (id.).

BP-1A at 3-16 to 3-17; BP-RG-1, at 4).[20] The Company noted that the 1993 CELT forecast and 1994 initial CELT forecast also underforecast actual summer peak in both the short term and medium term (Exh. BP-1A at 3-12 to 3-13, 3-16 to 3-17).

The Company noted that the 1994 final CELT forecast of winter peak load corresponded well with the actual winter weather-normalized peak for 1994/1995 (Exh. BP 1A at 3-10, n.5). Therefore, the Company did not prepare a 1994 normalized CELT forecast for winter peak load (id.).

(2) DSM

The Company provided three forecasts of DSM: (1) a base DSM scenario, which is the forecast of company-sponsored DSM savings used in NEPOOL's 1994 and 1995 CELT reports; (2) a high DSM scenario, which assumes an increase of ten percent in the annual post-1994 growth rate of the base scenario; and (3) a low DSM scenario, which assumes a decrease of 25 percent in the annual post-1994 growth rate of the base scenario (Exhs. BP-1A at 3-13 to 3-15; BP-RG-1, at 13). The Company asserted that the base DSM scenario likely overstates DSM savings achievable in the region and that, based on up-to-date data and studies, the low DSM scenario is the most likely forecast of future DSM savings (Tr. 6 at 136-137; Company Brief at 41).

In support of this assertion, the Company stated that, although NEPOOL has consistently revised its forecasts of company-sponsored DSM savings downward in each successive CELT report from 1990 to 1994, NEPOOL has continued to significantly overestimate DSM savings experienced by its member utilities (Exhs. BP-1A at 3-14, n.6; HO-RN-8, at 1, att. (a)). As an example, the Company indicated that NEPOOL's actual 1993 summer DSM savings were 918 MW (Exh. HO-RN-8, att. a). The 1990 CELT forecast projection of 1993 summer DSM was 1420 MW, an overprojection of 54.7 percent (id.). This

20 Although official data from NEPOOL was not available regarding the 1995 summer peak, the Company stated that NEPOOL has indicated that 1995 summer peak would be similar to, and perhaps slightly higher than, the 1994 summer peak (Exh. HO-RN-7).

projection was lowered in each successive CELT report until a projection of 1002 MW, an overprojection of nine percent, was made in 1994 (id.). Actual summer DSM savings for 1994 were not provided, but the Company indicated that NEPOOL also lowered its forecast of 1994 summer DSM savings from 1647 MW in the 1990 CELT report to 1034 MW in the 1994 CELT Report (id.). In addition, the Company indicated that over the 1991 through 1994 time period, the combined DSM savings of Massachusetts investor-owned utilities were less than projected savings (id.). The Company further indicated that a number of utilities in the region recently have reduced their DSM budgets and that a number of existing DSM programs will no longer be considered cost-effective due to the Court decision regarding environmental externalities (Exhs. HO-RN-8; HO-RN-4). See Massachusetts Electric Company v. Department of Public Utilities, 419 Mass 239 (1994).

(B) Analysis

BPD developed four summer and four winter demand forecasts based directly on the 1993, 1994, and 1995 CELT report reference forecasts and the initial 1994 CELT reference forecast. In addition, the Company developed two summer demand forecasts based on escalation of the 1994 summer peak by two different methods and one forecast based on the escalation of the 1994/1995 winter peak.

The Siting Board notes that it 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. Cabot Decision, 2 DOMSB at 273-274; Altresco-Lynn Decision, 2 DOMSB at 43; NEA Decision, 16 DOMSC at 354. Here, the Company provided demand forecasts based on four CELT forecasts from a three year period. The assumptions and methods varied primarily between the 1993 forecast and the later forecasts. Although the Company considered the assumptions and methods of the 1993 CELT forecast to be preferable to the more recent CELT forecasts, the Company acknowledged that the 1993 CELT forecast was based on dated information.[21] Nonetheless, since the record in this proceeding includes more recent CELT forecasts, the Siting Board will rely primarily on the more recent forecasts in its analysis of regional need in this proceeding.

In considering the remaining demand forecasts, the Siting Board examines first the forecasts of summer peak load, and then the forecasts of winter peak load. The Siting Board notes that because NEPOOL did not update its long-run forecast method for the 1995 CELT forecast, the 1994 final CELT forecast and the 1995 CELT forecast are identical in the years 1999 and beyond. Given that the Siting Board's consideration of need in this case focuses on a period of several years beginning in 1999, the initial years of projected operation assuming the proposed 1999 start-up date, it would be duplicative to include both the 1994 final CELT forecast and the 1995 CELT forecast in the consideration of summer need. Therefore, the Siting Board includes only the 1995 CELT forecast in its consideration of summer need.

The Siting Board notes that the primary difference between the long-run forecasts underlying the 1994 initial CELT forecast and the 1995 CELT forecast is the air conditioning penetration assumptions. NEPOOL assumed in the 1994 initial CELT forecast that commercial and residential air conditioning penetrations would increase with growth in personal income, but assumed in the 1995 CELT forecast that residential and commercial air conditioning penetrations would increase slightly or decrease in the first year of the forecast and then remain flat in later years. The Siting Board agrees with the Company that the air conditioning penetration assumptions included in the 1994 initial CELT forecast appear to be more reasonable than those included in the 1995 CELT forecast. Consequently, the Siting Board considers the 1994 initial CELT forecast, which is in essence the 1995 CELT forecast with an adjustment for air conditioning penetrations, to be an appropriate base case summer forecast.

Accordingly, the Siting Board finds that the 1994 initial CELT forecast is an appropriate base case summer peak load forecast for use in the analysis of regional need for the years 1999

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21 As a general principle, the Siting Board notes that it can find no reason to reject conclusions based on forecasts, due solely to the age of the forecast, without evidence that the information on which the forecast is based is no longer accurate.

and beyond. The Siting Board considers it appropriate to include the most recent CELT peak load forecast, the 1995 CELT forecast, in its consideration of regional need. Accordingly, the Siting Board finds that the 1995 CELT forecast is an appropriate low case summer peak load forecast for use in the analysis of regional need for the years 1999 and beyond.

With respect to the two summer peak load forecasts based on the escalation of "actual" 1994 summer peaks, the Company characterized the 1994 normalized 2.5 percent forecast as a reasonable base case forecast and the 1994 normalized CELT forecast as a reasonable high case forecast. The Siting Board notes that both forecasts combine a modeled future year growth trend with an adjusted base year peak load level reflecting a single recent year. This approach ignores the cyclical nature of the economy. For instance, both forecasts could predict inflated peak load over the long term if the actual 1994 peak load were at the high point of an economic cycle.[22]

Further, with respect to the 1994 normalized 2.5 percent forecast, the Siting Board notes that in previous cases it has reviewed forecasts based on an analysis of the historical relationship of an economic indicator and peak load. The Siting Board accepted such forecasts as alternative forecasts in evaluations of regional need but recognized that such forecasts were based on methods that are less sophisticated than other forecasts such as the CELT forecast.

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22 Additionally, we note that, by using the highest weather normalized peak and the actual peak, weather normalized as starting points for its 1994 normalized CELT forecast and the 1994 normalized 2.5 percent forecast, respectively, the Company incorporated 1994 normalized peak load values that exceed those recognized by NEPOOL by 314 MW for the 1994 normalized 2.5 percent forecast and by 918 MW for the 1994 normalized CELT forecast. As justification, the Company argues that NEPOOL's approach of using an average of candidate days to determine normalized peak load by season is affected by the number of candidate days included in the average. The Siting Board does not disagree with the Company's observation, and notes NEPOOL's method could include so large a range of candidate days that the reported peak load is biased downward. We note that in 1994, NEPOOL reported a summer peak based on one peak day, and are concerned that this lack of consistency may contribute to bias in NEPOOL's reported peak load. However, since we do not know the extent of any potential bias in NEPOOL's reported 1994 summer peak, we are hard-pressed to accept BPD's suggested use of the single day peak as an appropriate adjustment.

See, Cabot Decision, 2 DOMSB at 276-277; Altresco Lynn Decision, 2 DOMSB at 47; EEC Decision, 22 DOMSC at 236-237. Here, the Company has not provided a forecast based on an analysis of the historical relationship of an economic indicator and peak load, but rather has assumed that the actual 1994 summer peak load would grow at 2.5 percent per year over the forecast period based on "current expectations of economic growth." Further, the Company has not provided either data regarding a historical relationship between peak load growth and economic growth, or sufficient substantiation of its assertion that the economy will continue to grow at an annual rate of 2.5 percent over the forecast period. Thus, the Siting Board finds that the 1994 normalized 2.5 percent forecast is not an acceptable summer peak load forecast for use, here, in an analysis of regional demand.

However, the Siting Board recognizes that the CELT report-based forecasts that BPD has presented underforecast actual summer peak loads in the short-term. Thus, while acknowledging that the 1994 normalized CELT forecast may be inflated over the long-term, the Siting Board finds that the 1994 normalized CELT forecast is a possible high-case summer peak load forecast for use in an analysis of regional need for the years 1999 and beyond.

In considering the Company's forecasts of winter peak load, the Siting Board first notes that, due to the anticipated January 1, 1999 start-up date of the proposed project, review of winter need should begin with the 1998/1999 winter. The Siting Board further notes that its primary criticism of the 1995 CELT forecast was the air conditioning penetration assumptions reflected in that forecast. Given that air conditioning penetration assumptions do not have an impact on the winter peak load forecast, the Siting Board's criticism of the 1995 CELT's forecast of summer peak load does not extend to the forecast of winter peak load. Accordingly, the Siting Board finds that the 1995 CELT forecast is an appropriate base case winter peak load forecast for use in the analysis of regional need for the years 1998/1999 and beyond.

The Siting Board's concerns regarding the 1994 normalized 2.5 percent forecast are the same for both summer and winter peak load. Thus, the Siting Board finds that the 1994 normalized 2.5 percent forecast is not an acceptable winter peak load forecast for use, here, in an analysis of regional demand.

As noted above, the 1995 CELT forecast and the 1994 final CELT forecast are identical, beginning in the year 1999, and the most significant difference between the 1995 CELT forecast and the 1994 initial CELT forecast are assumptions related to air conditioning penetrations. Inasmuch as the 1995 CELT forecast has been accepted as a base case winter peak load forecast, it would be duplicative to include either the 1994 initial CELT forecast or 1994 final CELT forecast in an analysis of winter peak load. Consequently, the Siting Board will consider only the 1995 CELT forecast of winter peak load.[23]

Finally, the Company provided three forecasts of DSM -- a base scenario which is the most current NEPOOL forecast of DSM, a low scenario which discounts NEPOOL's projected DSM increases over 1993 levels by 25 percent, and a high scenario which inflates NEPOOL's projected DSM increases over 1993 levels by 10 percent. Although the Company considered the low DSM scenario to be an appropriate base case, the Company did not clearly specify why the 25 percent reduction in projected DSM growth rates was appropriate. The Siting Board recognizes that previous NEPOOL forecasts of company-sponsored DSM have exceeded actual DSM savings. However, between 1990 and 1994, NEPOOL has consistently lowered its forecast of company-sponsored DSM. Relative to the 1990 CELT forecast, NEPOOL had decreased its forecast of 1993 DSM savings by 29.4 percent as of the 1993 CELT forecast and had decreased its forecast of 1994 DSM savings by 37.2 percent as of the 1994 CELT forecast. NEPOOL's overprediction of actual 1993 DSM savings decreased from 54.7 percent in the 1990 CELT forecast to nine percent in the 1993 CELT forecast. Thus, NEPOOL's forecast of DSM savings have consistently decreased, and in recent years have come significantly closer to actual DSM savings.

The Siting Board also recognizes that a number of Massachusetts investor-owned

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23 Given uncertainties in forecasting demand, the Siting Board recognizes that it is reasonable to include a range of forecasts in its review of a Company's need analysis for a proposed project. Since the Siting Board has accepted a range of forecasts of summer peak load, it is acceptable, in the instant proceeding, to consider only one forecast of winter peak load.

utilities have overpredicted actual DSM savings and that a number of regional utilities have decreased their DSM budgets in recent years. However, it is not clear from the record in this case: (1) how the individual utilities forecast DSM savings over the long-term; (2) how individual utility forecasts of DSM are incorporated into the NEPOOL regional forecasts; or (3) whether NEPOOL takes into account the possibility of utility over-predictions and DSM budget reductions in forecasting DSM savings over the long-term.

Thus, in this case, the Siting Board does not consider it appropriate to adjust NEPOOL's most current forecast of Company-sponsored DSM in the base case. Accordingly, for the purposes of this review, the Siting Board finds that NEPOOL's base DSM scenario represents an appropriate base case forecast of DSM savings for use in the regional need analysis.

In addition, the Siting Board agrees with the Company that, there is a greater likelihood that company-sponsored DSM savings will be lower than what is predicted in the base case forecast rather than higher than what is predicted in the base case forecast. Thus, the Siting Board finds that the Company's high DSM scenario represents an appropriate high case forecast of DSM savings for use in the regional need analysis. The Siting Board also finds that the Company's low DSM scenario represents an appropriate low case forecast of DSM savings for use in the regional need analysis.

In sum, the Siting Board has accepted three forecasts of summer peak load -- the 1994 initial CELT forecast as a base case forecast, the 1995 CELT forecast as a low case forecast, and the 1994 normalized CELT forecast as a high case forecast -- and one forecast of winter peak load -- the 1995 CELT forecast as a base case forecast. In addition, the Siting Board has accepted three forecasts of DSM -- a base case, low case and high case. Each of the forecasts of peak load is adjusted by each of the three forecasts of DSM. Therefore, overall, the Siting Board reviews nine forecasts of adjusted summer peak load and three forecasts of adjusted winter peak load.

ii. Supply Forecasts

(A) Description

(1) Capacity Assumptions

BPD presented three supply scenarios based on the capacity projections in the 1995 CELT report -- a base supply scenario, a high supply scenario, and a low supply scenario (Exhs. BP-RG-1 at 5 to 13; HO-RR-29).[24] The Company asserted that the low supply scenario should be considered the most likely forecast of supply for the region (Exh. HO-RR-29; Company Brief at 43-44).

Mr. Graham stated that the base supply scenario reflects the resources included in the 1995 CELT Report,[25] updated to incorporate current information on actual and planned changes to NEPOOL supply (Exh. BP-RG-1, at 6). The Company stated that it made reductions to the 1995 NEPOOL supply projections to reflect: (1) the retirement of the Salem Harbor 1-3 units (303 MW summer, 305 MW winter) beginning in 1999; (2) removal of unsold portions of existing generation projects whose capacity is partially or wholly uncommitted at present (290 MW summer, 311 MW winter); (3) the outage of the Maine Yankee unit for a 12-month period beginning in March 1995 (870 MW summer, 880 MW winter); (4) the derating of the Maine Yankee unit by ten percent beginning in 1996 (87 MW summer, 88 MW winter); (5) utility buy-outs of NUG projects (ranging from 58 MW to 146 MW, summer and winter, over the forecast period); and (6) the removal of the capacity of the

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24 The Company provided separate summer and winter supply scenarios to account for the seasonal variation in the capacity rating of various NEPOOL units (Exh. BP-1A at 3-19, n.10).

25 The Company indicated that NEPOOL counts toward capability all existing plants, external purchases and sales, and committed utility and non-utility generation owned or contracted by NEPOOL member utilities (i.e., all non-utility generating units that are under construction and/or fully licensed, including any contract changes) (Exhs. BP-RG-1, at 6; HO-RN-1, att. i at 55).

proposed Taunton Energy Center ("TEC") beginning in 1998 (150 MW summer and winter)[26] (Exhs. BP-RG-1, at 6-8; HO-RR-29). The Company stated that it made additions to the 1995 NEPOOL supply projections to reflect (1) incorporation of 75 percent of the contracted capacity in New England Electric Systems' ("NEES") Green RFP beginning in 1996 (27 MW summer and winter),[27] and (2) inclusion of the NEC supply remaining on-island beginning in 1997 (15 MW summer, 16 MW winter) (Exhs. BP-RG-1, at 6-8; HO-RR-29). In addition, 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. BP-1A at 3-20 to 3-21).[28]

In explaining its changes to the 1995 NEPOOL supply projections, the Company asserted that NEES plans to retire the coal-fired Salem Harbor 1-3 units (Exhs. BP-1A at 3-19; HO-RN-16, att. d). In support of this explanation, the Company provided a copy of (1) the

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26 The Company indicated that the 1995 CELT Report included the TEC coal-fired project as committed capacity in 1998 under category "T" which signifies "regulatory approval received including building permit, not under construction" (Exhs. BP-RG-1, at 9; HO-RN-1, att. i at 33, 54). The Company stated that it removed the TEC project from committed capacity due to the pendency of the project's petition before the Siting Board and the current projected on-line date of 2000 (id.).

27 BPD stated that 75 percent rather than 100 percent of the contracted 36 MW under the NEES Green RFP was included to reflect the likelihood that not all projects will be built and uncertainties associated with developing new technologies (Exh. HO-RN-11). The Company noted that there has been significant environmental opposition to the Kenetech windpower project, which accounts for a large amount of the Green RFP capacity (id.).

28 The Company stated that, consistent with NEPOOL assumptions set forth in the June 1994 Generation Task Force Assumption Book ("1994 GTF"), beginning in 2001, the base case supply scenario assumes a reduction in the capacity value of the HQ II transmission line from 1,500 MW to 1,270 MW in the summer, and from 525 MW to 430 MW in the winter (Exhs. BP-1A at 3-21; HO-RN-14). BPD noted that the reliability benefits of the HQ II transmission line could be represented as a supply resource or as a reduction in required reserves (Exh. BP-1A at 3-20 to 3-21).

resource summary table from Massachusetts Electric Company's ("MECo")[29] most recent IRM filing in D.P.U. 94-112, which indicates that the units will be retired in the year 2000, and (2) a response to a data request in a 1994 Granite State Electric Company proceeding before the New Hampshire Public Utilities Commission which indicates that the units will be retired in 1999[30] (Exh. HO-RN-10). The Company indicated that the initial year of operation for the Salem Harbor 1-2 units was 1952 and that the initial year of operation for the Salem Harbor 3 unit was 1958 (Exh. HO-RN-16, att. d). The Company noted that the NEPOOL retirement guideline for coal-fired units is 40 years (id.).

With respect to uncommitted existing supply, the Company stated that this category includes two existing generation projects -- the Enron generating facility and the Great Bay Power project, which owns a portion of the Seabrook facility (Tr. 6, at 94). Mr. Graham asserted that the full capacity of the Enron facility (150 MW summer, 171 MW winter) is uncommitted but that the facility is operating and selling power to the short-term market (Exh. HO-RR-29; Tr. 6, at 96-97). He further stated that Enron recently joined NEPOOL and that the facility therefore is dispatched based on variable cost and availability, like other NEPOOL units (Tr. 6, at 98). Mr. Graham stated that the Great Bay Power project (140 MW summer and winter), which also has no long-term power sales agreements and sells power on the short-term market, is available whenever the remaining portion of the Seabrook facility is available (Exhs. HO-RR-29; HO-RR-43; Tr. 6, at 98). Mr. Graham explained that both projects are competing with the proposed project for power sales contracts and thus should not be considered committed resources for the purposes of determining capacity need (Exh. HO-RR-42). However, he noted that the full capacity of both the Enron and Great Bay Power projects is included in the Company's dispatch analysis (Exhs. HO-RN-35; HO-RN-44).

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29 MECo is a subsidiary of NEES.

30 The Company also provided a copy of an undated response to a data request in a Narragansett Electric Company proceeding before the Rhode Island Public Utilities Commission which indicated that the Company's probabilistic need assessment included the Salem Harbor 1-3 units as "at risk" capacity for early retirement (Exh. HO-RN-10).

See Section II.A.3.a.i, below. The Company asserted that its treatment of uncommitted existing supply is consistent with Siting Board precedent (Exh. HO-RR-42).

With respect to buy-outs of NUGs, BPD explained that recent utility buyouts of NUG projects that were not incorporated into the 1995 CELT report include: (1) the Fairfield Energy Venture ("FEV"), 32 MW summer and winter; (2) O'Brien, 54 MW summer and winter;[31] (3) Pepperell, 31.4 MW summer, 37.2 MW winter; (4) Ultrapower 5, 24.9 MW summer, 25.1 MW winter; and (5) Ultrapower 6, 24.9 MW summer, 25.1 MW winter (Exhs. BP-RG-1, at 7-8; HO-RR-29, att. a).[32] Mr. Graham stated that the FEV facility is still operating but that the other facilities are currently shut down (Tr. 6, at 101-104).[33] He stated that the capacity of the FEV facility was deducted from 1995 NEPOOL supply beginning in late 1997 to reflect the likelihood that Central Maine Power ("CMP") will close the facility due to high costs (Tr. 6, at 102).[34]

Finally, with respect to the derating of the Maine Yankee facility over the forecast

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[31] Mr. Graham stated that the buyout by Northeast Utilities ("NU") of its power purchase agreement with the 54 MW O'Brien unit was facilitated by a power marketer who will sell an equal amount of replacement power to NU at a lower price (Exh. BP-RG-1, at 7, n.1). He stated that the source of the replacement power is confidential and that therefore, only 50 percent of the 54 MW capacity of the O'Brien unit was deducted to reflect the possibility that a portion of the replacement power would come from outside NEPOOL (Tr. 6, at 100-101).

[32] BPD indicated that the 1995 CELT report reflects the buyouts of the Ashland, Beaverwood, Lowell, Alexandria and Timco NUG units, none of which are presently operating (Exh. BP-RG-1, at 7; Tr. 8, at 72).

[33] Mr. Graham stated that it is possible that the Pepperell facility has been bought by an entity that is interested in continuing to operate the facility, but that it is not clear whether it will be economic to do so (Tr. 6, at 102-103).

[34] Mr. Graham stated that the FEV facility was bought out by CMP, which planned to close it due to high operating costs, but that, in accordance with an agreement reached with the local town, CMP will keep the facility operating for three years and then reassess the economic situation (Tr. 6, at 102). He noted that it was likely that the facility would be closed after the three-year period due to the facility's high costs (id.).

period, the Company provided documentation from the Nuclear Regulatory Commission ("NRC") that the unit has been derated by 10 percent due to uncertainties related to the emergency core cooling system and containment analysis and that said derating will continue until the NRC reviews and approves new analyses (Exh. HO-RR-30). The Company asserted that the facility may have been operating at an unsafe capacity level and that the derating may continue indefinitely and may become permanent (id.).

For the low supply scenario, the Company assumed reductions to the base supply scenario to reflect: (1) the permanent retirement of all presently deactivated plants scheduled for reactivation in the 1995 CELT Report beginning in 2002 (227 MW summer, 229 MW winter); (2) the retirement of 50 percent of all coal-fired and oil-fired capacity operating beyond NEPOOL retirement guidelines beginning in 1999 (144 MW increasing to 1,020 MW summer, 171 MW increasing to 1097 MW winter);[35] and (3) the reduction in the capacity value of the HQ II transmission line to 50 percent of its present value beginning in 2001 (Exh. BP-RG-1, at 9-10).

The Company asserted that, compared to the base supply scenario, the low supply scenario represents a realistic assessment of the continuing availability of older NEPOOL units and the capacity value of an unbooked HQ II transmission line (Company Brief at 43, citing, Exh. BP-1A at 3-24). In support, BPD stated that a significant portion of the existing NEPOOL fossil-fired capacity has exceeded or will soon reach NEPOOL's plant retirement guidelines (Exhs. BP-1A at 3-23; HO-RN-16). BPD further stated that, contrary to NEPOOL assumptions that these units will continue to operate, a number are likely to be retired within the forecast period given increasing operating costs, equipment breakdown, and incremental capital costs, particularly related to increasing emission control requirements (Exhs. BP-1A at

35 The Company assumed that existing coal-fired capacity would be retired if it reached or was operating beyond NEPOOL retirement guidelines, while oil-fired capacity would be retired after operating at least five years beyond NEPOOL retirement guidelines (Exh. BP-1A at 3-23).

3-23; HO-RN-18).[36] Mr. Graham also stated that the move to a competitive generation market is likely to accelerate the retirement of existing NEPOOL units that are costly and inefficient (Tr. 6, at 68-71).

With respect to the HQ II transmission line, the Company explained that the availability of uncontracted power from Hydro Quebec, a winter peaking utility, is uncertain due to Hydro Quebec's own capacity needs and recent decisions to cancel or postpone a number of generating projects (Exh. BP-1A at 3-21 to 3-22). The Company indicated that NEPOOL may have overstated the capacity value of the unbooked HQ II transmission line, particularly in the winter, given that NEPOOL conducted its analysis of the capacity value of the transmission line prior to the cancellation of these projects (id.).

For the high supply scenario, the Company added capacity to the base supply scenario including: (1) the capacity of the Salem 3 unit (143 MW summer and winter); (2) all uncommitted portions of existing generation projects (190 MW summer, 211 MW winter); (3) 50 percent of the planned utility capacity additions classified as under licensing consideration in the 1995 CELT report (three MW increasing to 78 MW, summer and winter);[37] (4) 25 percent of the planned utility capacity additions classified as proposed in the 1995 CELT report (two MW increasing to 147 MW summer, two MW increasing to 224 MW winter); (5) 100 percent, instead of 75 percent, of the contracted capacity in NEES' Green RFP (an additional 10 MW summer and winter); and (6) 100 percent of the capacity of the Maine Yankee unit

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36 The Company stated that the requirements of the Federal Clean Air Act Amendments of 1990 ("CAAA"), including Phase II NOx limits which will become effective in 1999, are likely to impose significant costs on older fossil-fueled units (Exhs. BP-1A at 3-23; HO-RN-18). The Company also stated that the expense of emission control options will be compounded by the limited time over which incremental capital costs can be amortized given the age and limited remaining life of many of these units (Exh. HO-RN-18). The Company noted that other CAAA requirements regarding air toxics, fine particulates and further NOx requirements also may have a significant cost impact on these units in the 2000-2003 time-frame (Exh. BP-1A at 3-23).

37 The Company indicated that the TEC project was included in this category, beginning in 2000, to reflect the project's current startup plans (Exhs. BP-RG-1, at 12; BP-1A at 3-27, n.17).

beginning in 1997 (an additional 87 MW summer, 88 MW winter) (Exhs. BP-RG-1, at 11-12; HO-RR-29; HO-RR-30).

(2) Reserve Margin

The Company indicated that it incorporated reserve margins consistent with NEPOOL's current projections of required reserve margin (Exh. BP-1A at 3-28). The Company stated that, for the 1994 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.). 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.).[38] Mr Graham indicated that reserve requirements are higher in the winter than in the summer because HQ II is a larger and more certain supply source in the summer (Tr. 6, at 80-81).

(B) Analysis

The Company has presented a base supply scenario based on the 1995 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. The Company characterized the low supply scenario as the most likely forecast of supply, which the Siting Board should consider as the base case supply forecast.

As noted above, the Company's base supply scenario assumes the removal of the

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38 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. BP-1A, att. 3-9). 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.).

capacity of: (1) the Salem Harbor 1-3 units beginning in 1999; (2) uncommitted Enron and Great Bay capacity; and (3) recent NUG buyouts. In addition, the Company assumed that the Maine Yankee facility would be derated by ten percent over the forecast period. Here, the Siting Board considers the reasonableness of these assumptions.

With respect to the Salem Harbor 1-3 units, the Siting Board notes that, by 1999, these units will be operating beyond NEPOOL's retirement guidelines for coal-fired units. Although the Company provided copies of documents that were included in various regulatory proceedings to support its assertion that NEES will retire these units, the Siting Board is not persuaded that these documents are more current and accurate than NEPOOL's 1995 supply forecast. However, the Company has provided documentation that as of 1999, a number of other NEPOOL 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, the Siting Board accepts the Company's assumption of the retirement of Salem Harbor 1-3 units in 1999.

With respect to the capacity of the uncommitted existing supply, the Siting Board notes that both the Enron unit and the Great Bay Project, as a portion of the Seabrook unit, are members of NEPOOL. The record demonstrates that the Enron unit is dispatched on the basis of its variable costs and availability and that the Great Bay Project is dispatched when the Seabrook unit is dispatched. Thus, even though neither the Enron unit nor the Great Bay Project have power sales agreements, and both are in effect competing with the proposed project to meet regional need, both the Enron unit and the Great Bay Project are currently available to supply peak demand in the region. Therefore, the Siting Board finds that the base case supply scenario should include the combined capacity of the Enron unit and the Great Bay Project totalling 190 MW, summer and 211 MW, winter.[39]

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39 The Siting Board recognizes that uncommitted existing supply has been excluded from the base case supply forecast in previous reviews of proposed facilities. See, e.g., Cabot Decision, 2 DOMSC at 284-286. However, the record demonstrates that in this

With respect to the recent buyouts of NUG units, the Siting Board notes that all NUG units included in this category, with the exception of the FEV facility, are no longer operating. The Company suggested that after three years of continued operation, CMP likely will close the FEV unit due to its high costs. However, the record does not support a conclusion that the FEV unit will in fact be shut down. Accordingly, the Siting Board finds that the base supply scenario should include the capacity of the FEV unit, 32 MW summer and winter.

Finally, with respect to the assumption of the derating of the Maine Yankee unit by 10 percent over the forecast period, the Siting Board notes that documentation of the NRC's derating does not indicate if or when the unit will be allowed to operate at its full capacity. Therefore, for the purposes of this review, the Siting Board accepts the Company's assumption that the Maine Yankee unit will be derated by 10 percent over the forecast period.

As noted above, the Company asserted that the low supply scenario represents the most likely supply forecast, primarily because it reflects a realistic assessment of the continuing availability of older NEPOOL units and the capacity value of an unbooked HQ II transmission line. However, the Siting Board considers the retirement of the Salem Harbor 1-3 units, included in the base supply scenario, to be a reasonable representation of the potential retirement of capacity operating beyond NEPOOL retirement guidelines, particularly in the proposed on-line year and early life of the proposed project. Additional estimates of the retirement of existing capacity are appropriately reflected in the low case supply forecast. Further, the record in this case does not support a rejection of NEPOOL's most current assessment of the capacity value of an unbooked HQ II transmission line. An estimated reduction of the capacity of this line also is appropriate in the low case supply forecast.

Accordingly, the Siting Board finds that the Company's base supply scenario, as adjusted to include the capacity of the Enron unit, the Great Bay Project, and the FEV unit, represents an appropriate base case supply forecast for use in the analysis of regional need. In

case, all of the capacity considered to be uncommitted existing supply is owned by NEPOOL members and is dispatched as needed based on NEPOOL's operating guidelines.

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, 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 37 summer need forecasts (Exh. HO-RR-29). Thirty-six of the summer need forecasts were developed by adjusting each of four demand forecasts (1993 CELT forecast, 1994 initial CELT forecast, 1994 normalized CELT forecast, 1995 CELT forecast),[40] by each of three DSM scenarios, and comparing each of the resulting twelve adjusted demand forecasts with the three supply forecasts (id.). The remaining summer need forecast was based on a comparison of the 1994 normalized 2.5 percent forecast, adjusted by the low DSM scenario, with the low supply forecast ("Company's base need scenario") (id.). Of these 37 summer need forecasts: (1) 30, or 81 percent, demonstrate a need for at least 252 MW of capacity in 1999; (2) 34, or 92 percent, demonstrate a need for at least 252 MW of capacity in 2000; and (3) 36, or 97 percent, demonstrate a need for at least 252 MW of

[40] Because the 1994 final CELT forecast and the 1995 CELT forecast are identical in the long-run, the Company excluded the 1994 final CELT forecast from its count of need forecast scenarios (Exh. BP-RG-1 at 14, n.14).

capacity in 2001 (id.). See Table 1. The Company's base need scenario showed a need for 2,414 MW in 1999, with a greater need in subsequent years. See Table 1.

In addition, the Company developed 37 winter need forecasts for 1998/1999, including (1) 36 winter need forecasts based on a comparison of four demand forecasts (the 1993 CELT forecast, 1994 initial CELT forecast, 1994 final CELT forecast, and 1995 CELT forecast), each adjusted by three DSM scenarios, with the base, high and low supply forecasts; and (2) the Company's base need scenario (id.). For the years 1999/2000 and beyond, need forecasts based on the 1994 final CELT forecast were omitted since they were identical to those based on the 1995 CELT forecast (id.). Of the winter need forecasts: (1) 12, or 32 percent, demonstrate a need for at least 252 MW of capacity in 1998/1999; (2) 26 or 93 percent, demonstrate a need for at least 252 MW of capacity in 1999/2000; and (3) 28, or 100 percent, demonstrate a need for at least 252 MW of capacity in 2000/2001 (id.). See Table 2. The Company's base need scenario shows a need for 1,200 MW in 1998/1999, with greater need in subsequent years (id.). See Table 2.

(B) Analysis

In considering the Company's forecasts of summer peak load, the Siting Board has found that: (1) the 1994 initial CELT forecast is an appropriate base case summer peak load forecast for use in the analysis of regional need for the years 1999 and beyond; (2) the 1995 CELT forecast is an appropriate low case summer peak load forecast for use in the analysis of regional need for the years 1999 and beyond; and (3) the 1994 normalized CELT forecast is a possible high case summer peak load forecast for use in an analysis of regional need for the years 1999 and beyond.

In considering the Company's forecasts of winter peak load, the Siting Board has found that the 1995 CELT forecast is an appropriate base case winter peak load forecast for use in the analysis of regional need for the years 1998/1999 and beyond.

In considering the Company's DSM forecasts, the Siting Board has found that: (1) NEPOOL's base DSM scenario represents an appropriate base case forecast of DSM savings for use in the regional need analysis; (2) the Company's high DSM scenario represents an appropriate high case forecast of DSM savings for use in the regional need analysis; and (3) the Company's low DSM scenario represents an appropriate low 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, as adjusted to include the capacity of the Enron unit, the Great Bay Project, and the FEV unit, 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.

While the Siting Board has accepted the 1995 CELT forecast of summer peak load and the 1994 normalized CELT forecast of summer peak load, the Siting Board has identified concerns with these forecasts. As a result of these concerns, the Siting Board places more weight on the base case forecast of summer peak load. Accordingly, the Siting Board here considers the need for the proposed project based on two compilations of the Company's need forecasts, as adjusted by the Siting Board, for summer peak load -- a compilation including only those need forecasts based on the 1994 initial CELT forecast, and an overall compilation of need forecasts based on all three summer peak load forecasts. The following table sets forth the number of summer need forecasts that demonstrate a need for at least 252 MW in the years 1999 through 2001.

Forecast	# Cases	1999	2000	2001
1994 Initial CELT	9	7 (78%)	9 (100%)	9 (100%)
All others	18	10 (56%)	14 (78%)	17 (94%)
Total	27	17 (63%)	23 (85%)	26 (96%)

The capacity positions under the summer need forecasts, as adjusted by the Siting Board, are shown in Table 3. Considered with the base case DSM forecast and the base case supply forecast, the first year that a need is demonstrated for at least 252 MW is: (1) 2000 for the 1994 initial CELT forecast (854 MW); (2) 2001 for the 1995 CELT forecast (352 MW); and (3) before 1999 for the 1994 normalized CELT forecast. See Table 3.

The Siting Board has accepted only one winter peak load forecast -- the 1995 CELT forecast of winter peak load. The number of winter need forecasts that demonstrate a need for at least 252 MW in each year, from 1998/1999 through 2000/2001, is as follows:

Forecast	# Cases	1998/1999	1999/2000	2000/2001
1995 CELT	9	1 (11%)	8 (89%)	9 (100%)

The capacity positions under the winter need forecasts, as adjusted are shown in Table 4. The first year of winter need for at least 252 MW under the 1995 CELT forecast, assuming the base case DSM forecast and base case supply forecast, is 1999/2000 (835 MW). See Table 4.

In sum, 17 of the 27 summer need forecasts, including seven of the nine need forecasts reflecting the base case demand forecast, show a need for at least 252 MW in 1999, while 23 summer need forecasts, including all of the need forecasts reflecting the base case demand forecast, show a need for at least 252 MW in 2000. In addition, eight of the nine winter need forecasts show a need for at least 252 MW in 1999/2000.

Accordingly, based on the foregoing, the Siting Board finds a likely need for 252 MW or more of additional energy resources in New England for reliability purposes beginning in 1999, and a clear need for 252 MW or more of additional energy resources in New England for reliability purposes beginning in 2000 and beyond.

b. Massachusetts

BPD asserted that there is a need for new capacity in Massachusetts by the year 1999 or earlier (Company Brief at 54). To support its assertions, BPD presented a series of forecasts of demand and supply for Massachusetts, based primarily on the 1993, 1994 and 1995 forecast documents and other data published by NEPOOL, and, as necessary, prorated to Massachusetts by the Company (Exhs. BP-1A at 3-31 to 3-42; HO-RR-45). The Company stated that it then compared its demand and supply forecasts to produce a series of need forecasts (Exh. BP-RG-1, at 18).

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 need forecasts.

i. Demand Forecasts

(A) Description

In developing load forecasts for Massachusetts, BPD indicated that it relied primarily on NEPOOL Massachusetts-specific forecasts of adjusted peak load which correspond to the regional CELT Report forecasts of adjusted load (Exh. BP-1A at 3-32).[41] The Company presented five forecasts of Massachusetts unadjusted summer peak load and five forecasts of

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[41] BPD stated that NEPOOL prepares individual state forecasts by allocating the regional forecast to the individual states (Tr. 8, at 65-66). BPD also stated that NEPOOL's individual state forecasts include the effects of NUG-netted-from-load and Company-sponsored DSM (Exh. BP-1A at 3-32, n.20).

Massachusetts unadjusted winter peak load (id. at 3-32, 3-33; Exhs. BP-RG-1, at 16-17; HO-RR-45). BPD stated that it added the NEPOOL reference Massachusetts DSM forecast for each year to the adjusted load forecasts in order to produce Massachusetts unadjusted load forecasts consistent with its regional load forecasts (Exh. BP-1A at 3-33). BPD further stated that, in order to prepare forecasts of adjusted load, it combined these forecasts with three forecasts of DSM savings based on NEPOOL's most current forecast of Massachusetts-specific DSM savings. Overall, the Company provided thirteen forecasts of Massachusetts adjusted summer peak load and thirteen forecasts of Massachusetts adjusted winter peak load (Exh. HO-RR-45).

(1) Demand Forecast Methods

The Company indicated that it developed forecasts of Massachusetts peak load corresponding to each of the demand forecasts presented in the regional need analysis, with the exception of the 1994 normalized CELT forecast (id.; Exhs. BP-1A at 3-32, 3-33; BP-RG-1, at 16-17).[42] The Company stated that the forecasts corresponding to the 1993 CELT forecast ("1993 NEPOOL Massachusetts forecast") and 1994 final CELT forecast ("1994 final NEPOOL Massachusetts forecast") were based directly on NEPOOL forecasts of Massachusetts summer and winter peak load for 1993 and 1994 respectively, which were included in the NEPOOL report, "Energy and Peak Load Forecast Exhibits, Massachusetts," for 1993 and 1994 (Exh. BP-1A at 3-32 to 3-33).[43]

The Company indicated that NEPOOL did not prepare a Massachusetts-specific forecast in conjunction with either the 1994 initial CELT report or the 1995 CELT report (id.; Exh.

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42 The Company stated that a Massachusetts forecast corresponding to the 1994 normalized forecast was not developed because data for the Massachusetts 1994 weather-normalized summer peak load was not available (Exh. BP-1A at 3-33, n.21).

43 Mr. Graham reported that NEPOOL's forecasts of coincident peak were utilized rather than the forecasts of "own-state" load (Exh. BP-RG-1, at 16, n.5). He noted that the coincident peak forecasts were equal to or slightly lower than the "own-state" forecast for all years (id.).

BP-RG-1, at 16). The Company stated that it developed Massachusetts summer and winter peak forecasts corresponding to the 1994 initial CELT forecast ("1994 initial NEPOOL Massachusetts forecast") and 1995 CELT forecast ("1995 NEPOOL Massachusetts forecast") by prorating the 1994 final NEPOOL Massachusetts forecast (Exhs. BP-1A at 3-34; BP-RG-1, at 16). To develop the 1994 initial NEPOOL Massachusetts forecast, the Company multiplied the 1994 final NEPOOL Massachusetts forecast by the ratio of the 1994 initial CELT forecast to the 1994 final CELT forecast (Exh. BP-1A at 3-34). To develop the 1995 NEPOOL Massachusetts forecast, the Company multiplied the 1994 final NEPOOL Massachusetts forecast by the ratio of the 1995 CELT forecast to the 1994 final CELT forecast (Exh. BP-RD-1, at 16).[44] The Company noted that, like the corresponding regional forecasts, the 1994 final NEPOOL Massachusetts forecast and the 1995 NEPOOL Massachusetts forecast are identical in the years 1999 and beyond (Exh. BP-RG-1, at 16, n.6). In addition, the Company developed summer and winter peak load forecasts corresponding to the 1994 normalized 2.5 percent forecast ("1994 Massachusetts normalized 2.5 percent forecast") (Exh. HO-RR-45).[45]

Consistent with the regional need analysis, the Company asserted that the 1994 Massachusetts normalized 2.5 percent forecast was the most likely forecast of demand (Company Brief at 55). In addition, BPD stated that the concerns it raised relative to the various regional need forecasts also would apply to the corresponding Massachusetts need forecasts (Tr. 8, at 66).

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44 BPD asserted that the ratio used to develop the 1995 NEPOOL Massachusetts forecast is conservative in that it assumes that Massachusetts will receive a prorated share of any increase in demand exhibited in the 1995 CELT forecast relative to the 1994 final CELT forecast, even though the Massachusetts economy has improved more than the New England economy as a whole (Exh. BP-RG-1, at 17).

45 The Company also provided a second 1994 Massachusetts normalized 2.5 percent forecast for Massachusetts using NEPOOL's reported peak as a starting point (Exh. HO-RR-45). For the reasons noted in Section II.A.2.a.i, above, the Siting Board does not consider the second 1994 Massachusetts normalized 2.5 percent in its review of Massachusetts need.

(2) DSM

The Company provided three forecasts of Massachusetts DSM: (1) a base Massachusetts DSM scenario taken directly from the 1994 report, "NEPOOL Participant Planned Demand-Side Management Impacts on the NEPOOL Forecast, 1994-2009," which is NEPOOL's most recent state-by-state forecast of DSM savings; (2) a high Massachusetts DSM scenario which assumes that the post-1994 DSM growth rate is ten percent higher than the base Massachusetts DSM scenario; and (3) a low Massachusetts DSM scenario which assumes that the post-1994 DSM growth rate is 25 percent lower than the base Massachusetts DSM scenario (Exh. BP-1A at 3-33 to 3-34). Consistent with its regional need analysis, the Company asserted that the low Massachusetts DSM scenario was the most likely forecast of future DSM savings (Exh. HO-RR-45).

(B) Analysis

BPD has provided five demand forecasts for its Massachusetts need analysis which correspond to the demand forecasts presented in its regional need analysis. The Siting Board reviewed the regional demand forecasts in Section, II.A.2.a.i, above.

For the reasons set forth in Section II.A.2.a.i.(B), above, the Siting Board will rely on the more recent CELT-based forecasts instead of the 1993 NEPOOL Massachusetts forecast in its analysis of Massachusetts demand in this proceeding.

Consistent with its findings concerning the remaining regional demand forecasts, the Siting Board finds that: (1) the 1994 initial NEPOOL Massachusetts forecast is an appropriate base case summer peak load forecast for use in the analysis of Massachusetts need for the years 1999 and beyond; (2) the 1995 NEPOOL Massachusetts forecast is an appropriate low case summer peak load forecast for use in the analysis of Massachusetts need for the years 1999 and beyond; and (3) the 1995 NEPOOL Massachusetts forecast is an appropriate base case winter peak load forecast for use in the analysis of Massachusetts need for the years 1998/1999 and beyond.[46]

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 which are consistent with the Company's regional supply scenarios (Exhs. BP-1A at 3-35 to 3-40; BP-RG-1, at 17). The Company stated that its base Massachusetts supply scenario reflects the committed capacity that (1) is owned or contracted by Massachusetts utilities, regardless of location, and (2) was included in the 1995 CELT Report (Exhs. BP-1A at 3-35 to 3-36; BP-RG-1, at 17). The Company indicated that for utilities with sales in more than one state, supplies were prorated based on the average ratio of each utility's projected Massachusetts summer peak demand to its total system projected peak demand over the forecast period (Exh. BP-1A at 3-37).[47]

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46 The Company did not submit a Massachusetts forecast similar to the 1994 normalized CELT forecast.

47 The Company stated that NEES, Eastern Edison Company ("Eastern Edison"), WMECo, and Massachusetts Municipal Wholesale Electric Company ("MMWEC") make out of state sales (Exh. BP-1A at 3-37). The Company indicated that its prorating ratio for MMWEC was determined based on the proportion of its annual sales to out-of-

The Company stated that it adjusted the Massachusetts-specific information from the 1995 NEPOOL supply forecast to reflect current information on actual and planned changes to 1995 NEPOOL supply and such adjustments were consistent with its adjustments in the regional base case supply scenario (id.). The Company noted that each such adjustment was analyzed on a utility-by-utility basis in order to make the appropriate allocation to Massachusetts (id. at 3-37 to 3-38). In Section II.A.2.a.ii.(B), above, the Siting Board found that the regional base case supply scenario should include the combined capacity of the Enron unit and the Great Bay Project. The Company has indicated that Massachusetts' share of the combined capacity of the Enron unit and the Great Bay Project is 138.8 MW summer and 148.2 MW winter (Exh. BP-RG-1, exh. 22).[48]

The Company stated that its Massachusetts low case supply scenario is comparable to the regional low case supply scenario (id. at 17). 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 (Exh. BP-1A at 3-39). In addition, the Company stated that its Massachusetts high case supply scenario also is comparable to the regional high case supply scenario (id.). In allocating supply increases to Massachusetts, the Company indicated that where existing or proposed facilities (1) could be associated with a specific utility, capacity was allocated to that utility, and (2) could not be associated with a specific utility, capacity was allocated to Massachusetts based on the average ratio of Massachusetts to NEPOOL peak load over the forecast period (id. at 3-40).

Consistent with the regional need analysis, the Company asserted that the low case supply scenario was the most likely forecast of Massachusetts supply (Exh. HO-RR-45).

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state entities because peak demand was not available (id.).

48 In Section II.A.2.a.ii.(B). above, the Siting Board found that the base case supply scenario also should include the capacity of the FEV unit, 32 MW summer and winter. However, because this unit is owned by CMP, none of its capacity is allocable to Massachusetts utilities.

(2) Reserve Margins

BPD stated that it assumed the same percentage reserve margin requirements for Massachusetts as were assumed for the region (Exh. BP-1A at 3-40 to 3-41). Thus, as noted in Section, II.A.2.a.ii.(A)(2), above, BPD utilized NEPOOL reserve margins for the years 1994 through 2000 and assumed that reserve margins would remain constant at their year 2000 levels for the remainder of the forecast period.

(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 case supply scenario, as adjusted to include the proportionate capacity of the Enron unit and the Great Bay Project, 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 Company assumed the same percentage reserve margin requirements for Massachusetts as were assumed for the region. Consistent with its finding 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

The Company developed 28 summer need forecasts for Massachusetts (Exh. HO-RR-45). Twenty-seven of these were developed by adjusting each of three demand forecasts (the 1993 NEPOOL Massachusetts forecast, 1994 initial NEPOOL Massachusetts forecast, and 1995 NEPOOL Massachusetts forecast),[49] by each of the three DSM scenarios and comparing each of the nine resulting adjusted demand forecasts with the three supply forecasts (id.). The remaining summer need forecast was based on a comparison of the 1994 Massachusetts normalized 2.5 percent forecast, adjusted by the low DSM scenario, with the low supply forecast ("Company's Massachusetts base need scenario") (id.). All of the Company's summer need scenarios demonstrated a need for 252 MW by 1999 (id.). See Table 5.

In addition, the Company developed 37 winter need forecasts for 1998/1999 including (1) 36 winter need forecasts based on a comparison of four demand forecasts (the 1993 NEPOOL Massachusetts forecast, 1994 initial NEPOOL Massachusetts forecast, 1995 NEPOOL Massachusetts forecast, and 1994 final NEPOOL Massachusetts forecast), each adjusted by base, high, and low DSM scenarios, with the base, high, and low supply forecasts, and (2) the Company's Massachusetts base need scenario. For the years 1999/2000 and beyond, need forecasts based on the 1994 final NEPOOL Massachusetts forecast were omitted, resulting in a total of 28 need forecasts for those years. None of the Company's winter need forecast scenarios show a need for at least 252 MW of capacity in the year 1998/1999. Fourteen need forecast scenarios, or 50 percent, show a need for at least 252 MW of capacity in 1999/2000, while 28 need forecast scenarios, or 100 percent, show a need for at least 252 MW in 2000/2001. See Table 6. The Company's Massachusetts base need scenario showed a need for: (1) 21 MW in 1998/1999; (2) 586 MW in 1999/2000; and (3) 851 MW in 2000/2001. See Table 6.

(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 within the 1998/1999 to 2002 time frame.

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[49] The Company excluded the 1994 final NEPOOL Massachusetts forecast because it duplicates the 1995 NEPOOL Massachusetts forecast (Exh. HO-RR-45, att. j).

The Siting Board has found that: (1) the 1994 initial NEPOOL Massachusetts forecast is an appropriate base case summer peak load forecast for use in the analysis of Massachusetts need for the years 1999 and beyond; (2) the 1995 NEPOOL Massachusetts forecast is an appropriate low case summer peak load forecast for use in the analysis of Massachusetts need for the years 1999 and beyond; and (3) the 1995 NEPOOL Massachusetts forecast is an appropriate base case winter peak load forecast for use in the analysis of Massachusetts need for the years 1998/1999 and beyond.

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 case supply scenario, as adjusted to include the proportionate capacity of the Enron unit and the Great Bay Project, 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 Siting Board's concerns regarding the 1995 CELT forecast extend to the 1995 Massachusetts NEPOOL forecast of summer peak load. These concerns affect the weight the Siting Board places on this forecast. Consequently, the Siting Board places more weight on the base case forecast -- the 1994 initial NEPOOL Massachusetts forecast. However, as noted above, all Massachusetts summer need forecasts, including those that incorporate the base case supply scenario as adjusted above, show a need for at least 252 MW in 1999. See Table 7.

Accordingly, based on the foregoing, the Siting Board finds need for 252 MW or more of additional energy resources in Massachusetts for reliability purposes beginning in 1999 and beyond.[50]

3. Economic Need

a. New England

i. Description

The Company asserted that there is a need for the proposed facility on economic efficiency grounds (Company Brief at 46). 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. at 46, 49-51).

In support of its assertions with respect to the existing NEPOOL dispatch system, BPD provided a series of detailed economic analyses based on existing NEPOOL dispatch practices[51] for the 20-year period, 1999 through 2018, which compared the total incremental variable costs of two scenarios -- one that included the dispatch of the proposed facility ("Berkshire-in case") and one without the proposed facility ("Berkshire-out case") (Exhs. BP-1A at att. 3-31; HO-RN-35; HO-RR-44(red.)). The Company stated that these analyses demonstrate that the proposed facility would provide significant, assured economic efficiency benefits to the region that would be equal to the difference in the region's cost of electricity under these two scenarios (Exh. BP-1A at 3-43 to 3-44). The Company stated that such economic efficiency benefits

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[50] The Siting Board notes that Massachusetts winter need forecasts demonstrate a later year of need than the Massachusetts summer need forecasts. See Table 8.

[51] Mr. Graham 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 (Tr. 7, at 97). He stated that the units with the least expensive variable costs are dispatched first, with the exception of must-run units (those units which have to be run for contractual, transmission, or other reasons) which are dispatched whenever they are available (id.).

would accrue to the region due to (1) the displacement by the proposed project of more expensive power sources in NEPOOL's dispatch order, and (2) differences in incremental fixed cost requirements in the Berkshire-in case relative to the Berkshire-out case (id.).

The Company stated that it used the ENPRO model to simulate NEPOOL's dispatch on an hourly basis over the forecast period (id. at 3-44).[52] The Company indicated that inputs into the ENPRO model included: (1) a load duration curve;[53] (2) load growth scenarios; (3) plant specific information for existing units;[54] (4) escalation factors for current dispatch prices;[55]

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52 The Company indicated that the ENPRO model simulates the dispatch of all NEPOOL power plants on an hourly basis, taking into account changes in NEPOOL load, unit additions and retirements, changes in unit dispatch costs and resulting changes to the NEPOOL system dispatch (Exh. BP-1A at 3-44).

53 BPD indicated that it used NEPOOL's actual 1991 hourly loads as a base year and assumed that the hourly load shape and system load factor would remain constant over the forecast period (Exh. BP-1A at 3-46). BPD asserted that this was a conservative assumption, given that NEPOOL is projecting a small increase in its load factor over time (Exh. HO-RN-25). The Company explained that a higher load factor would require older, more expensive and more polluting units to operate at a higher capacity factor than assumed in the analyses, and that the energy displaced by the proposed project under a higher load factor scenario would be higher in cost and more polluting (id.).

54 The Company stated that the plant-specific information for each existing unit included generating capacity, fuel type(s), fuel costs, variable non-fuel costs, average heat rate, unit availability, emissions data, must-run status, and other operating characteristics (Exh. BP-1A at 3-45). BPD stated that this information was obtained primarily from FERC Form 1 filings, utility performance filings with the Department of Public Utilities ("Department"), NEPOOL NX-12 forms, and the 1994 NEPOOL Generation Task Force report (“1994 GTF") (id.). BPD indicated that average heat rate and unit availability were assumed to remain constant over the forecast period (Exh. HO-RN-28). BPD also indicated that existing gas/oil dual fuel units were assumed to burn gas for nine months of the year (Exh. HO-RN-27).

55 The Company stated that base-year plant dispatch prices were based on actual NEPOOL dispatch price data obtained from the NEPOOL Monthly Fuel Summary for 1994 (Exh. BP-1A at 3-45 to 3-46). The Company also stated that actual 1994 base year dispatch prices, of which fuel and variable O&M are the largest part, were escalated based on the 1994 GTF (Exhs. HO-RN-27; HO-A-8).

(5) scheduled and projected plant retirements and additions[56] including the addition of new generic capacity to meet projected regional capacity requirements; (6) classification of specific units as must-run units;[57] and (7) operating characteristics and dispatch price for the proposed facility (id. at 3-44 to 3-49).

With respect to load growth scenarios, the Company stated that hourly loads were adjusted over the forecast period based on two different load growth scenarios for unadjusted peak -- the 1993 CELT forecast and the 1994 final CELT forecast,[58] each paired with the base DSM scenario and a base supply forecast derived from the 1994 final CELT report (Exh. BP-1A at 3-46).[59]

In its analysis, BPD assumed three types of new generic capacity: (1) 225 MW gas-fired combined cycle ("GTCC") units; (2) 500 MW integrated coal gasification combined cycle ("IGCC") units; and (3) 80 MW oil-fired combustion turbines for peaking capacity (id. at

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[56] The Company stated that plant retirement assumptions are consistent with the base case supply scenario (Exh. HO-RR-29).

[57] BPD classified all of NEPOOL's conventional hydropower, baseload external purchases, portions of certain existing fossil units, and certain purchases from existing and committed NUGs as must-run (Exh. BP-1A at 3-44). BPD stated that its list of must-run capacity reflects its understanding of NEPOOL's must-run capacity (Exh. HO-RN-24).

[58] The Company indicated that these two load growth scenarios were selected because they represent the highest and lowest load growth forecasts in the regional need analysis and, as such, provide reasonable upper and lower bounds for the magnitude of cost savings over time (Exh. BP-1A at 3-46).

[59] The Company did not update its dispatch analysis based on the 1995 CELT report (Exh. BP-RG-1, at 19). As noted in Section II.A.2.a.i.(A)(1), above, the Company stated the 1995 CELT forecast and 1994 final CELT forecasts are identical beginning in the year 1999. The Company stated that, although there were several changes in supply in the 1995 CELT report relative to the 1994 final CELT report, such changes were relatively small and would not have a significant impact on the results of the analyses (id.).

3-47).[60] BPD stated that the type and timing of the generic capacity additions were based on an optimal NEPOOL generation mix (id.).[61] BPD assumed that the performance characteristics of the new generic capacity would remain unchanged over the forecast period (Tr. 8, at 29-30). BPD also assumed that the GTCC units would be less efficient than the proposed project over the forecast period and therefore, that the proposed facility would be dispatched ahead of the GTCC units (Tr. 8, at 30).[62]

With respect to the costs and operating characteristics of the proposed facility, the Company provided analyses based on two differing assumptions for heat rate -- (1) an originally assumed approximate heat rate of 7,000 British thermal units per kilowatt hour ("Btu/kwh") ("higher heat rate"), and (2) an updated heat rate[63] ("lower heat rate") (Exhs. BP-1A at 3-31; HO-RN-35; HO-RN-44). BPD indicated that its analyses assume a fuel

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60 BPD stated that the cost and performance characteristics of the generic units were obtained from the 1993 Electric Power Research Institute ("EPRI") Technical Assessment Guide ("TAG") Report ("1993 TAG") (Exh. BP-1A at 3-48). BPD further stated that initial fuel prices and escalators were obtained from the 1994 GTF (id.). The Company noted that costs, performance characteristics and fuel prices of the GTCC and IGCC units were consistent with those used in the technology alternatives analysis (id. at 3-47 to 3-48).

61 The Company stated that NEPOOL's total cost would be minimized over time with 45 percent baseload capacity, 40 percent cycling capacity and 15 percent peaking capacity (Exh. HO-RN-26). The Company noted that, in adding generic capacity, all of the IGCC units and 30 percent of the GTCC units were designated as baseload capacity, and the remaining 70 percent of the GTCC units were designated as cycling capacity (id.).

62 Mr. Graham stated that the proposed project has a fairly significant heat rate advantage over the GTCC units in the analysis and that significant technology improvements would have to be assumed for the generic units to reach the efficiency level of the proposed facility (Tr. 8, at 30). He added that some improvement in technology would lead to improved efficiency in the generic units over time but would not affect the analysis in the short term (id.).

63 Pursuant to Siting Board regulations, the Company has requested that the updated heat rate be considered proprietary and be afforded confidential treatment.

cost based on a firm gas supply from the wellhead to the proposed facility ("firm gas supply") (Tr. 7, at 101-103). BPD indicated that a firm gas supply, which would have a high demand charge and low variable cost, would be an appropriate supply given NEPOOL's current dispatch practices, which are based on variable cost (id.). However, the Company stated that it actually anticipates contracting for firm transportation only from Wright, New York to the project ("Wright gas supply"), an arrangement which would have a higher variable cost and lower total cost than a firm gas supply (id. at 98-99, 102). The Company explained that the Wright gas supply would be advantageous, if NEPOOL dispatch practices change as a result of electric industry restructuring so that dispatch would be based on total cost (id. at 102).[64]

The Company stated that the ENPRO model provided the NEPOOL system variable dispatch costs associated with each set of assumptions (Exh. BP-1A at 3-47). In order to assess total cost savings, the Company stated that variable dispatch costs were added to the incremental capital costs of the proposed facility[65] and generic units for each case to produce total costs (id. at 3-48). The Company stated that the NEPOOL system-wide savings attributable to the proposed facility would be the difference in total costs between the Berkshire-in case and Berkshire-out case (id. at 3-48 to 3-49). The Company stated that the annual nominal savings were discounted to 1995 dollars to obtain the net present value ("NPV") of economic efficiency savings attributable to the proposed project (id. at 3-49).[66]

The Company provided Berkshire-out and Berkshire-in cases for the years 1999 through 2018, for the following scenarios: (1) 1993 CELT forecast, higher heat rate and firm

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64 The Company also stated that use of the Wright fuel supply under existing NEPOOL dispatch practices would cause the proposed project to drop in the dispatch order (Exh. HO-RR-39 (red)). However, BPD asserted that the proposed facility would nearly always be dispatched when available because its capacity factor would continue to be almost equal to its availability rating (id.).

65 BPD stated that capital costs of the proposed facility were obtained from the financial pro-forma of the project (Exh. BP-1A at 3-47).

66 BPD indicated that annual nominal savings were discounted to 1995 dollars using the weighted average cost of capital (ten percent) in the 1994 GTF (Exh. BP-1A at 3-49).

gas supply ("1993 CELT dispatch scenario"); (2) 1994 final CELT forecast, higher heat rate and firm gas supply ("1994 CELT dispatch scenario"); and (3) 1994 final CELT forecast, lower heat rate and firm gas supply ("updated 1994 CELT dispatch scenario") (Exhs. HO-RN-35; HO-RR-44(red.)).[67]

The Company indicated that under the 1993 CELT dispatch scenario (1) there would be a positive annual net economic benefit to the region in each year of the forecast period, and (2) the proposed project would result in $295.9 million NPV of savings in 1995 dollars over the 20-year forecast period (Exh. BP-1A at 3-49, att. 3-31).[68]

BPD indicated that, under the 1994 CELT dispatch and the updated 1994 CELT dispatch scenarios, there would be a positive annual net economic benefit to the region in all years of the forecast period with the exception of 1999, when the proposed project would increase total costs (id. at att. 3-31; HO-RR-44(red.)).[69] The Company noted that the Berkshire-in case assumes that 100 percent of the proposed project is sold in 1999 even though there is no identified capacity need until 2000 (Exh. HO-RN-32).[70] In addition, the Company stated that, over the forecast period, the NPV in savings in 1995 dollars provided by the

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67 The updated 1994 CELT dispatch scenario also corrects for an error in the timing of the addition of the first two generic GTCC units in the 1994 CELT dispatch scenario Berkshire-out case (Exh. HO-RR-44(red.)).

68 The Company indicated that the NPV of the total economic efficiency savings, discounted by ten percent to 1999 dollars would be $328.50 million (Exh. BP-1A at att. 3-31). The Company also indicated that, savings in 1995 dollars, for the first five years of the operation of the proposed project would be: (1) $35.10 million in 1999; (2) $37.85 million in 2000; (3) $16.79 million in 2001; (4) $37.85 million in 2002; and (5) $20.30 million in 2003 (id.).

69 The Company indicated that total costs would increase by $24.23 million under the 1994 CELT dispatch scenario and $23.10 million under the updated 1994 CELT dispatch scenario (Exhs. BP-1A at att. 3-31; HO-RR-44(red.)).

70 The Company also noted that although the proposed project provides savings in dispatch costs in 1999, these savings are not enough to compensate for the fixed capacity charges of the proposed project (Exh. HO-RN-32).

proposed project would be (1) $241.7 million under the 1994 CELT dispatch scenario, and (2) $248.6 million under the updated 1994 CELT dispatch scenario (Exhs. BP-1A at att. 3-31; HO-RR-44(red.)).[71] The Company also indicated that the NPV of savings in the first five years of facility operation, in 1995 dollars, would be (1) $57.15 million, or 23 percent of the total savings, under the updated 1994 CELT dispatch scenario, and (2) $113.2 million, or 38 percent of the total savings, under the 1993 CELT dispatch scenario (Exhs. BP-1A at att. 3-31; HO-RR-44(red.)). The Company expressed a high degree of confidence in the analysis in the short-term, but stated that there was more uncertainty in the projected savings as the forecast extended over the long-term (Tr. 8, at 33-34).

The Company asserted that the cost savings attributable to the proposed facility are likely to be even greater under electric industry restructuring than they are under existing NEPOOL dispatch (Company Brief at 49-50). The Company stated that, with electric industry restructuring, regional dispatch likely would change to a bidding system, and that total plant costs, not just variable costs, would be reflected in a facility's bid (id. at 49; Tr. 7, at 101-102). As will be discussed in Section II.C.2.a, below, the Company asserted that the total costs of the proposed facility are below the operating costs of many existing generating units. Therefore, the Company argued that the proposed facility likely would be dispatched more often under a total cost dispatch system than under the current dispatch system and would displace greater amounts of more expensive generation (Company Brief at 50, citing, Exhs. HO-RN-39; HO-V-21; BP-RG-32; Tr. 8, at 46-56).

ii. Position of the Parties

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[71] The Company indicated that, under the updated 1994 CELT dispatch scenario, the NPV of the total economic efficiency savings, discounted by ten percent to 1999 dollars would be $276 million (Exh. HO-RR-44(red.)). The Company also indicated that, under the updated 1994 CELT dispatch scenario, total costs would increase in 1999 by $23.1 million in 1999 dollars and that savings in current year dollars, for the next four years of the operation of the proposed project would be: (1) $40.79 million in 2000; (2) $18.95 million in 2001; (3) $23.5 million in 2002; and (4) $23.65 million in 2003 (id.).

CCBA asserted that the Company had "dispensed tremendous misinformation surrounding the need for the proposed power plant and the alleged benefit to electric rate payers" (CCBA Brief at 1). CCBA also argued that there is no need for the proposed project, "based on extensive research" (id.). In response, BPD argued that the failure of CCBA to support its position with record information evidences CCBA's inability to refute the evidence in the record that demonstrates need for the proposed project (Company Reply Brief at 1).[72]

iii. 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 1995 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. Cabot Decision, 2 DOMSB at 296-300; Altresco Lynn Decision, 2 DOMSB at 22-27; 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 the total cost of generating power in the New England region through the displacement of more expensive sources of power. Cabot Decision, 2 DOMSB at 292-296; Altresco Lynn Decision, 2 DOMSB at 61-65;

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[72] BPD also took issue with CCBA's reference to "facts" that were not a part of the official administrative record in this proceeding, and urged the Siting Board to strike those portions of CCBA's brief which relied on such facts or, in the alternative, to "only accord [those portions] the appropriate amount of weight" that they are due (id. at 1, 2).

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. See 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. In addition, the Siting Board has indicated that, since regional economic efficiency gains are not contractually guaranteed, unlike economic efficiency gains associated with specific PPA's, the degree to which such regional gains are assured would be a critical factor in its evaluation of regional need for economic efficiency purposes. The Siting Board also has identified the magnitude and timing of such gains as critical to its review.

Here, the Company has provided a detailed description of the methods and assumptions used in its analysis of economic efficiency savings. BPD's use of two load growth forecasts in developing dispatch scenarios allows the Siting Board to evaluate the degree to which economic efficiency savings are assured, given uncertainties in future load growth.[73]

Although the Company's analysis recognizes uncertainties in future load growth, it does not account for future uncertainty in fuel price forecasts. A range of fuel price forecasts would have strengthened this analysis, particularly since (1) there is no fuel contract for the proposed facility, and (2) the fuel supply assumed for the analysis is not that anticipated for the proposed facility.

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[73] The Siting Board does not further consider the 1994 CELT dispatch scenario.

In addition, while the Company's analyses are generally based on reasonable assumptions, certain assumptions are questionable over a 20-year period. For instance, the Company assumes that the proposed project will have a significantly lower heat rate than the generic GTCC units throughout the 1999-2018 time period and that the fuel mix for the dual fuel oil/gas units will remain consistent at nine months gas/three months oil.

Nevertheless, the analyses provided by the Company indicate that under both the 1993 CELT dispatch scenario and updated 1994 CELT dispatch scenario, the proposed project would provide substantial economic efficiency savings over the 20-year period from 1999 to 2018. The NPV of savings, in 1995 dollars, over the 20-year period would range from $248.58 million under the updated 1994 CELT dispatch scenario to $295.87 million under the 1993 CELT dispatch scenario. The Siting Board agrees with the Company that there is more confidence in the dispatch analysis in the short-term, and notes that the NPV of savings for the first five years of the proposed project, in 1995 dollars, would be (1) $57.15 million, or 23 percent of the total savings, under the updated 1994 CELT dispatch scenario, and (2) $113.2 million, or 38 percent of the total savings, under the 1993 CELT dispatch scenario.[74] Thus, BPD has established that New England would recognize economic savings of a substantial magnitude from the operation of the proposed project during its first five years of operation under a range of demand forecasts.

Under each of the dispatch analyses, the first year of economic efficiency savings is coincident with the first year of capacity need. Thus, economic efficiency savings would begin to accrue in 1999 under the 1993 CELT dispatch scenario and in 2000 under the updated 1994 final CELT dispatch scenario.

Accordingly, the Siting Board finds that BPD has established that there will be a need in New England for 252 MW of additional energy resources from the proposed project for

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[74] The Siting Board notes that the ratio of NPV in 1995 dollars to NPV in 1999 dollars is 90.067 percent (Exhs. BP-1A at att. 3-31; HO-RR-44(red.)). To obtain the NPV, in 1995 dollars for the first five years of each dispatch analysis, the annual economic efficiency savings (or costs) were discounted by ten percent per year to 1999 and then multiplied by 90.067 percent.

economic efficiency purposes beginning in the first year of capacity need in New England. Further, consistent with its findings regarding reliability need in New England, the Siting Board finds that there will be a likely need in New England for 252 MW of additional energy resources from the proposed project for economic efficiency purposes beginning in 1999 and that, there will be a clear need in New England for 252 MW of additional energy resources from the proposed project for economic efficiency purposes beginning in 2000.

b. Massachusetts

The Company asserted that Massachusetts will require the capacity represented by the proposed facility for economic efficiency purposes (Company Brief at 56). The Company stated that economic efficiency benefits will accrue to direct purchasers of electricity from the proposed facility and to NEPOOL as a whole, because system-wide costs would be lower with the operation of the proposed facility than without operation of the proposed facility (Exh. HO-RN-38, at 1). The Company further stated that, because the purchasers of electricity from the proposed facility are not known and may change over time, it is reasonable to assume that regional economic efficiency benefits would accrue to Massachusetts in proportion to Massachusetts' energy consumption (id.). BPD noted that, over the 1999 to 2009 period, NEPOOL calculates that Massachusetts will account for approximately 44.5 percent of NEPOOL's annual "net energy for load"[75] (id. at 1, and att. a). The Company stated that Massachusetts customers should realize a similar percentage of the economic efficiency benefits provided by operation of the proposed facility (id. at 1).[76]

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75 The Company explained that net energy for load represents projected electricity consumption, including sales and losses (Exh. HO-RN-38).

76 The Company's analysis indicates that operation of the proposed facility would provide Massachusetts with NPV savings in 1995 dollars ranging from (1) $110.62 million under the updated 1994 CELT dispatch scenario to $131.66 million under the 1993 CELT dispatch scenario, over the 20-year period from 1999 to 2018, and (2) $25.43 million under the updated 1994 CELT dispatch scenario to $50.38 million under the 1993 CELT dispatch scenario, over the five-year period from 1999 to 2003 (Exhs. HO-RN-38; BP-1A at att. 3-31; HO-RR-44(red.)).

In Section II.A.3.iii, above, the Siting Board determined that New England would recognize economic savings of a substantial magnitude from the operation of the proposed project during its first five years of operation under a range of demand forecasts. In addition, the Siting Board found that there would be a need in New England for 252 MW of additional energy resources from the proposed project for economic efficiency purposes beginning in the first year of capacity need in New England.

Although the record in this case does not support a finding regarding the extent of savings that would accrue to Massachusetts, it is clear that Massachusetts will share in the regional economic efficiency benefits provided by the operation of the proposed facility, once those benefits begin. Accordingly, the Siting Board finds that there is a need in Massachusetts for the additional energy resources produced by the proposed project for economic efficiency purposes beginning in the year in which economic efficiency benefits begin in the region.

4. Environmental Need

a. Description

BPD 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 the generation of less efficient, more polluting existing facilities by the proposed facility (Exh. BP-1A at 3-50 to 3-51; Company Brief at 51). To demonstrate environmental benefits realized from the displacement of existing sources of air pollution, the Company presented a dispatch analysis[77] comparing the emissions of the following pollutants associated with the combustion of fossil fuels both with and without the proposed project: (1) sulfur oxides ("SOx"); (2) NOx; (3) particulates ("PM-10"); (4) volatile organic compounds ("VOCs"); (5) CO; and (6) carbon dioxide ("CO_2") (Exhs. BP-1A at att. 3-32; HO-RN-35; HO-RR-44(red.)).

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77 BPD 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. BP-1A at 51). See Section II.A.3.a.i, above.

BPD indicated that it used the ENPRO model and plant-specific emissions data[78] to determine regional emissions for each pollutant in tons per year ("tpy") (Exh. BP-1A at 3-50). BPD stated that future CAAA compliance requirements for SOx and NOx were incorporated into the analysis,[79] with the exception of NOx emissions offsets that will be required for the proposed facility and generic additions (Exhs. HO-RN-28; HO-RN-31).[80] In addition, as noted in Section II.A.3.a.i, above, BPD assumed that average heat rate and unit availability would

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78 Mr. Graham stated that emission rates for existing units were based primarily on actual emission rates and that emission rates for the generic units were based on recent permitted emission rates for new facilities in the region (Exh. BP-1A at 3-50; Tr. 8, at 38-40).

79 BPD stated that the analysis assumes reductions in existing SOx and NOx emission rates (Tr. 8, at 39). BPD stated that facilities that currently can burn fuels with either low or high sulfur content were assumed to burn the lower sulfur content fuel in order to comply with Massachusetts and CAAA acid rain regulations (Exh. HO-RN-28). In addition, BPD stated that NOx emissions were based on a Northeast States for Coordinated Air Use Management assessment of NOx reduction requirements which differ slightly from the most recent NOx reduction requirements (id.).

The Company noted that improvements in emission rates would more than offset load growth for SOx and NOx emissions between 1996 and 1999, but not for other types of emissions (Exh. HO-RN-51). The Company explained that the CAAA requires a greater percentage reduction in SOx and NOx emission rates from power plants than the projected increase in NEPOOL average net energy for load (id.). The Company further noted that SOx and NOx emissions reductions likely would be achieved by fuel switching and/or capital investments in additional control equipment (id.).

80 The Company stated that it would be difficult to anticipate the impact of NOx emission offsets on total NOx emissions attributable to electric generation in the region because NOx emissions offsets may not come from within New England or from electric generation (Exh. HO-RN-35). The Company noted that, to the extent that the generic units have higher emissions than the proposed facility, the dispatch analysis may overstate NOx emission reductions attributable to the proposed facility and underestimate the relative costs of the generic facilities (id.).

remain constant over time,[81] and that dual fuel oil/gas units would burn gas for nine months and oil for three months over the 20-year analysis period (Exhs. HO-RN-28, HO-RN-27).

The Company's dispatch analysis assumes that the proposed project would delay the need for generic capacity and thus displace such capacity (Exhs. HO-RR-79; HO-RN-35; HO-RR-44(red.)). The Company indicated that its dispatch analysis also reflects the difference between the proposed project and generic units in displacing older units (Exhs. HO-RR-79; HO-RN-35; HO-RR-44(red.)).

The Company's analysis demonstrates that, under the 1993 CELT dispatch scenario, operation of the proposed project would provide emissions savings over the 20-year period 1999 through 2018 and would provide emissions reductions for each pollutant for each year with the exception of (1) 2001, when VOC emissions would be increased by one ton, and (2) 2006 and 2007, when all emissions would increase (Exh. BP-1A at att. 3-32).[82] See Table 9.

The Company indicated that emissions savings would be greater under the updated 1994 CELT dispatch scenario than under the 1993 CELT dispatch scenario and that, under the updated 1994 CELT dispatch scenario, operation of the proposed project would result in emissions reductions for each pollutant for each year with the exception of (1) 2010, when VOC emissions would increase by one ton, and (2) 2017 and 2018, when all emissions would increase (id.; Exh. HO-RR-44(red.)). See Table 9.

BPD's analysis demonstrates that, under both dispatch scenarios, emissions savings over the first five years of the analysis for all pollutants, with the exception of VOCs, would constitute at least 50 percent of the total savings over the 20-year period (id.). Under the updated 1994 CELT dispatch, emissions savings in 1999 would be greater than the total

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[81] The Company argued that this assumption is conservative since unit aging and the addition of pollution control equipment would likely result in the degradation of these performance characteristics (Exh. HO-RN-28).

[82] BPD explained that increases in emissions would result from (1) the difference in the size of the proposed facility and the assumed size increment for the GTCC units, and (2) the relationship between capacity need and the size of the unit added (Exh. HO-RN-33).

emissions savings over the next four years for SOx, NOx, CO, and a significant percentage of the total emissions savings over the five-year period, 1999 through 2003, for all pollutants (Exh. HO-RR-44(red.)). See Table 9.

The Company asserted that Massachusetts will require the capacity represented by the proposed facility for environmental purposes (Company Brief at 56). However, the Company indicated that it is difficult to quantify emissions benefits to Massachusetts because (1) emissions may migrate beyond the borders of the state in which they originated, and (2) the generic units have not been assigned to particular locations (Exh. HO-RN-38). The Company stated that, assuming the generic units would be distributed across the region in proportion to sales, emissions displacement allocated to Massachusetts would be slightly less than the 44.5 percent ratio of Massachusetts to NEPOOL net energy for load because Massachusetts is a net importer of electricity (id.).

b. 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. 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.

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 DOMSC 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.[83] 1 DOMSB at 333.

Here, the Company has provided a comprehensive 20-year analysis of dispatch effects on regional emissions for the period 1999 to 2018. However, unlike earlier petitioners, BPD has not provided a dispatch analysis that would allow the Siting board to determine the net impact that the proposed project would have on the total emissions from generation facilities located in Massachusetts. The Siting Board notes that all of the proposed project's emissions are in Massachusetts, and that, absent a dispatch analysis or other means of verifying how much of the displacement will be in Massachusetts, the regional dispatch analysis cannot be used as the basis for a finding of environmental need in Massachusetts. Nonetheless, the Siting Board here evaluates the Company's dispatch analysis and the environmental benefits provided to the region by the proposed project.

The Company's analysis includes sufficient documentation, regarding the methods and

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[83] The Siting Board also noted that similarly favorable long-term air quality benefits may also be achieved through a combination of (1) implementing new base load generation with low emissions, and (2) implementing new emissions controls at existing generating units capable of reducing emissions rates from such units. Altresco Lynn Decision, 2 DOMSB at 101.

assumptions used in the calculating the net impact that the proposed project would have 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. In addition, although the Company assumes constant emission rates over time, the Company's analysis takes into account likely emission reductions for SOx and NOx that will be required in 1999 under the CAAA and Massachusetts acid rain regulations.

The Company's dispatch analysis shows a clear net reduction in emissions of all pollutants modelled over the 20-year forecast period, with a large percentage of the reductions occurring in the first five years of operation of the proposed facility. Further, the updated 1994 CELT dispatch scenario shows very significant benefits in the year 1999. The Company assumes that 100 percent of the proposed project is sold in 1999 even though, under this dispatch scenario, there is no identified capacity need until 2000. Thus, for the year 1999, the updated 1994 CELT dispatch scenario clearly shows the environmental benefit of displacing existing generation.

Although the dispatch analyses show long-term reductions in emissions, it is not clear whether these reductions would result in permanent benefits and would be directly related to operation of the proposed facility. First, the Company's analysis allows the displaced generation to be increasingly redispatched over time with continued load growth.[84] In addition, as in the economic efficiency analysis, the Company assumes that the proposed project will have a significantly lower heat rate than the generic GTCC units, with associated lower annual emissions throughout the 1999 though 2018 period. Further, the larger 252 MW size of the proposed project, relative to the assumed 225 MW size of the first and later units of GTCC capacity, potentially increases the displacement of oil-fired and other older units in some years

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84 We note that for several regional or worldwide air quality concerns, including O_3, 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 SOx, NOx, VOCs, and CO_2.

of BPD's analysis. Finally, by not incorporating NOx emissions offsets that would be required of the proposed facility and generic facilities, and by assuming a constant fuel mix for the dual fuel units and a consistent heat rate for the generic units, the Company may have overstated emissions reductions due to the operation of the proposed facility in the long-term.

The Siting Board notes that these uncertainties in the dispatch analysis are not susceptible to easy resolution since they relate, primarily, to uncertainties about the attributes of plants that will be built in the distant future. 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. Therefore, the Siting Board notes that, in the future, it may be appropriate for our review of environmental need to focus on the displacement of older generating units, in the period of time prior to a capacity need.

Accordingly, the Siting Board finds that: (1) the Company has established that, under the updated 1994 CELT dispatch scenario, operation of the proposed project would provide short-term regional air quality benefits; (2) the Company has not established that operation of the proposed project would provide significant long-term regional air quality benefits; and (3) the Company has not established that operation of the proposed project would provide air quality benefits to Massachusetts.

5. Conclusions on Need

The Siting Board has found that there is a likely need for 252 MW or more of additional energy resources in New England for reliability purposes beginning in 1999 and beyond and a clear need for 252 MW or more of additional energy resources in New England for reliability purposes beginning in 2000 and beyond. In addition, the Siting Board has found that there is a need for 252 MW or more of additional energy resources in Massachusetts for reliability purposes beginning in 1999 and beyond.

The Siting Board also has found that, consistent with its findings regarding reliability need in New England, there will be a likely need in New England for 252 MW of additional energy resources from the proposed project for economic efficiency purposes beginning in

1999 and that there will be a clear need in New England for 252 MW of additional energy resources from the proposed project for economic efficiency purposes beginning in 2000. In addition, the Siting Board has found that there is a need in Massachusetts for 252 MW of additional energy resources from the proposed project for economic efficiency purposes beginning in the year in which economic efficiency benefits begin in the region.

Further, the Siting Board has found that: (1) the Company has established that, under the updated 1994 CELT dispatch scenario, operation of the proposed project would provide short-term regional air quality benefits; (2) the Company has not established that operation of the proposed project would provide significant long-term regional air quality benefits; and (3) the Company has not established that operation of the proposed project would provide air quality benefits to Massachusetts.

Based on a showing of need for 252 MW or more of additional energy resources in the Commonwealth for reliability purposes beginning in 1999 and beyond and a likely need for 252 MW or more of additional energy resources in the region beginning in 1999 and beyond, the Siting Board finds that the proposed project is needed to provide a necessary energy supply for the Commonwealth beginning in 1999 and beyond.

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. Cabot Decision, 2 DOMSB at 334; Altresco Lynn Decision, 2 DOMSB at 107; EEC (remand) Decision, 1 DOMSB at 296.

2. Identification of Resource Alternatives

a. Description

To address the identified need for additional energy resources, BPD proposes to construct a nominal 252 MW gas-fired, combined-cycle facility in Agawam, Massachusetts, which would commence commercial operation in 1999 (Exh. BP-1A at 1-1). The Company stated that it conducted a two-phase screening process to identify all potential alternative technologies and then to identify those technologies that would be practical, cost-effective alternatives to meet the identified need at the proposed site (id. at 4-2 to 4-3; Tr. 5, at 102).

The Company stated that, in the first stage of its screening process, it assessed the feasibility of all electric generation and storage technologies included in the 1993 TAG and 1994 GTF reports, based on the criteria of: (1) technology development status;[85] (2) siting/permitting feasibility; (3) cost effectiveness; (4) diversification from oil; (5) compatibility with baseload/intermediate generation; and (6) potential ability to develop

[85] BPD stated that the 1993 TAG report includes a technical development rating for each technology which is based on EPRI's confidence in the technical and cost data provided in the report (Exh. BP-1A at 4-13). BPD explained that technologies with significant commercial operating experience, and thus the highest confidence level, are rated as "mature," those with beginning commercial operating experience are rated as "commercial," and those whose concept has been demonstrated but are not considered commercial are rated as "demonstration" (id.). BPD stated that additional 1993 TAG report classifications are "pilot" and "laboratory" and that certain technologies are not even given a rating due to technical immaturity (Exh. HO-A-12). BPD noted that a classification of mature, commercial or demonstration was not considered to be a fatal flaw in this stage of the analysis (id.). The Company further noted that the 1993 TAG report is the most recent available TAG report (Tr. 5, at 9).

sufficient incremental resources in the region to meet the identified need[86] (Exhs. HO-A-1; HO-A-8; HO-A-12). The Company stated that based on this assessment, it eliminated technologies found to have serious fatal flaws[87] and narrowed the list of potential technologies to include: (1) a GTCC facility;[88] (2) an atmospheric fluidized bed coal ("AFBC") facility; (3) a pressurized fluidized bed coal ("PFBC") facility; (4) an IGCC facility in which coal is converted to gas and then burned in a conventional combined-cycle unit; (5) a pulverized coal ("PC") facility; (6) a wind energy system;[89] (7) a biomass facility using a wood-fired circulating fluidized bed combustion unit; (8) a municipal solid waste ("MSW") facility using a mass burn boiler; and (9) a phosphoric acid fuel cell ("fuel cell") (Exhs. HO-A-12; BP-1A at 4-5 to 4-11).[90]

BPD stated that, in the second stage of the screening process, it assessed the potential of each of the aforementioned technologies to reliably meet the identified need at the proposed

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[86] BPD noted that this criterion was relevant to locally resource-constrained technologies for which there are inadequate incremental resources in the region to meet the identified need, such as geothermal power, hydroelectric power and scrap-tire boilers (Exh. HO-A-12).

[87] The Company stated that technologies eliminated from further review due to fatal flaws included: (1) nuclear fission; (2) nuclear fusion; (3) geothermal power; (4) photovoltaic cells; (5) solar thermal; (6) tidal power; (7) ocean thermal; (8) hydroelectric; (9) oil-steam; (10) combustion turbines; (11) diesels; (12) scrap-tire boilers; and (13) storage technologies (Exh. HO-A-12; Tr. 5, at 102).

[88] BPD indicated that the proposed project differs from a generic GTCC facility in that the cost and performance data for the proposed project were based on the Company's pro forma while the cost and performance data for the GTCC facility were obtained from the 1993 TAG report (Exh. BP-1A at 4-16 to 4-17).

[89] The Company assumed a 50 MW wind energy system made up of 143 individual 350 kilowatt units (Exh. BP-1A at 4-8).

[90] BPD indicated that where the 1993 TAG report described variations on a technology, the Company considered the best variation of the technology in terms of technical maturity, cost, reliability and environmental impacts (Exh. HO-A-1).

site[91] with a reasonable degree of assurance, based on five criteria: (1) technical maturity;[92] (2) reliability; (3) siting/permitting feasibility; (4) cost-effectiveness; and (5) local resource potential (Exh. BP-1A at 4-3, 4-12).

The Company indicated that, in this second stage, it eliminated technologies found to have two or more significant flaws that would likely render them incapable of meeting the identified need (Exh. HO-A-2). Based on its analysis, BPD stated that a wind energy system would not be cost-effective,[93] was classified as a demonstration technology, could not be sited at

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91 The Company indicated that, consistent with previous Siting Board reviews, it assumed that the alternative technologies would be located at the proposed site (Exh. HO-A-2). The Company noted that the proposed site is 40 acres, insufficient to site all of the generic technologies with the exception of the GTCC, MSW and fuel cell units (Exh. BP-1A at 4-13). However, the Company noted that if it acquired additional land immediately adjacent to the proposed site, the site size would increase to 70 acres, which would be a sufficient size for each of the alternative technologies with the exception of the wind energy system (id.).

In addition, Mr. Graham discussed the possibility of packaging a combination of alternative technologies at sites scattered throughout Massachusetts (Tr. 5, at 99-102). Mr. Graham asserted that the costs and environmental impacts of a number of small projects would be greater than those of a single large project (id.).

92 The Company stated that, in this stage of the analysis, it assumed that those technologies classified by the 1993 TAG report as "mature" or "commercial" would be sufficiently technically mature to be capable of meeting the identified need with a reasonable degree of assurance and that technologies classified as demonstration would have a significant flaw (Exhs. BP-1A at 4-12 to 4-13; HO-A-12; Tr. 5, at 9). BPD stated that the 1993 TAG report classified: (1) the GTCC and PC technologies as mature; (2) the AFBC, MSW, and biomass technologies as commercial; and (3) the PFBC, IGCC, wind energy, and fuel cell technologies as demonstration (Exh. BP-1A at 4-12).

93 In calculating the cost-effectiveness of the wind energy system, the Company assumed that capital costs would decline from 1992 to 1999, that there would be a federal tax credit for the first ten years of operation, that the annual capacity factor would be 30 percent, and that the peak coincidence factor would equal the annual capacity factor (Exh. BP-1A at 4-8). The Company noted that all other technologies would have annual average capacity factors and peak coincidence factors at least double that of the wind technology (id. at 4-8 to 4-9).

the proposed site, and could only be sited in areas of high wind (Exh. BP-1A at 4-7 to 4-9). BPD also stated that a biomass facility would be limited in size to 50 MW, would not be cost-effective and must be located close to fuel supplies (id. at 4-10 to 4-11).[94] BPD further stated that an MSW facility would be limited in size to 40 MW, would not be cost-effective,[95] likely would have siting/permitting restraints,[96] and must be located close to fuel supplies (id. at 4-9 to 4-10). Finally, BPD stated that fuel cells would not be cost-effective and are classified as a demonstration technology (id. at 4-11). Therefore, the Company eliminated the wind energy system, biomass facility, MSW facility, and fuel cells from further review (id. at 4-14 to 4-15).

Thus, the Company identified five technologies -- one gas-fired technology and four coal-fired technologies -- that would be capable of meeting the identified need in lieu of the Company's proposed project (id. at 4-15). Specifically, the Company stated that the technologies that potentially could meet the identified need include: (1) a GTCC facility with oil backup ("GTCC alternative"), which is the type of technology planned for the proposed project; (2) an AFBC facility ("AFBC alternative") (3) a PFBC facility ("PFBC alternative"); (4) an IGCC facility ("IGCC alternative"); and (5) a PC facility ("PC alternative") (id.).

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[94] BPD stated that the size and efficiency of biomass facilities are limited by availability, transportation costs and heat content of the fuel and that existing units have been bought out by utilities due to high costs (Exh. BP-1A at 4-11; Tr. 5, at 28). BPD also stated that it investigated the use of urban or recycled wood, but concluded that it was unlikely that an adequate and reliable supply of such fuel would be available to supply a generating unit of any significant size (Exh. HO-RR-17). In addition, BPD stated that it reviewed a whole-tree boiler as a technology option, but did not analyze this technology because of its classification as a "pilot" technology and the necessity of being located in close proximity to heavily forested regions with substantial land dedicated to supplying such a plant (Exh. HO-RR-18).

[95] In calculating the cost of the MSW facility, BPD assumed a current tipping fee -- the fee paid to owners of MSW facilities for waste disposal -- of $40 per ton, escalated at the rate of inflation (Exh. BP-1A at 4-10).

[96] The Company stated that MSW facilities tend to have high toxic air emissions (Tr. 5, at 25-26). The Company also stated that it is unlikely that a new MSW plant would be permitted in Massachusetts without the retirement of an existing MSW plant, due to state policies limiting the use of combustible waste in MSW plants (Exh. HO-RR-19).

BPD stated that the GTCC alternative and the AFBC alternative are mature technologies and are the standard generating technology choices for new baseload generation in the northeast (id. at 4-4 to 4-5). BPD also stated that the PC alternative is a mature technology and is commonly used for baseload generation in the United States (id. at 4-7). However, BPD indicated that the PFBC alternative, which uses a pressurized flue gas to improve operating efficiencies relative to the AFBC, and the IGCC alternative are not yet commercially available (id. at 4-6 to 4-7).[97]

b. Analysis

The record demonstrates that BPD used a two-stage screening process to identify potential alternative technologies. 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 nine technologies to distinguish those that could reliably meet the identified need at the proposed site with a reasonable degree of assurance and eliminated those technologies that were determined to have significant flaws in two or more of its stated criteria.

The Siting Board notes, however, that it is not clear how the Company chose certain technologies for comparison with the proposed project and eliminated others from further review in its second stage of analysis. The record fails to indicate whether there was a specific nominal levelized cost above which the Company determined that a technology would not be cost-effective in its second stage of analysis. Further, flaws found in the biomass and fuel cell technologies were also present in certain of the technology alternatives included for further review. For example, one reason given by the Company for not evaluating biomass units and

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97 The Company noted that the PFBC technology is currently being demonstrated at a size of 80 MW and that, therefore, three 80 MW units were assumed for the proposed site (Exh. BP-1A at 4-6). BPD also noted that the IGCC technology has been demonstrated in limited applications (id. at 4-6 to 47).

fuel cells as technology alternatives to the proposed facility was their small size: multiple units of each technology would be required to generate enough power to meet the identified need of 252 MW. The Company nonetheless evaluated one other alternative technology -- the PFBC alternative -- where the size of generation unit also would require construction of multiple units on-site. The Company also determined that a flaw in the biomass facility was the requirement that it be located close to fuel supplies, while coal-fired facilities were included in the analysis even though there is no rail line for coal transportation in close proximity to the proposed site. Further, the Company determined that a flaw in fuel cells was their classification as a demonstration technology while the PFBC and IGCC alternatives, also classified as demonstration technologies, were included.

Thus, based on the Company's criteria, it is not clear why the biomass facility and fuel cells were eliminated from further review in the second stage of the Company's analysis, while the PFBC, which arguably has two significant flaws, was retained. Nonetheless, the Siting Board finds that, based on a review of the record information regarding cost and reliability of the biomass and fuel cells, the potential for these technologies to meet the identified need at a reasonable cost is uncertain and BPD's decision to eliminate them from further review is appropriate.

In making this finding, the Siting Board does not intend to suggest that the development of renewable resources would not contribute to a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. On the contrary, the Siting Board recognizes that renewable resource projects may represent a source of electricity with low environmental impacts that contributes to the diversity of the Commonwealth's energy supply. However, the record demonstrates that, at this time, these technologies are not sufficiently developed to represent cost-effective alternatives to the proposed project. The Siting Board expects that renewable resources will supplement, rather than substitute for, the energy provided by the proposed project, and notes that these technologies will merit a more comprehensive review as their costs and reliability improve.[98]

Thus, for purposes of this review, the Company has demonstrated that the GTCC alternative, AFBC alternative, PFBC alternative, IGCC alternative, and PC alternative would potentially address the identified need, and in its review of the cost, environmental impacts, and reliability of the proposed project, the Siting Board compares the proposed project to these five alternatives.

3. Comparison of 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 indicated that all technology alternatives were compared on the same level of net electric output, 252 MW (Exh. BP-1A at att. 4-2). The Company also indicated that cost and performance data for the proposed project was based on the Company's pro forma while cost and performance data for the technology alternatives were obtained from the 1993 TAG report (id. at 4-16 to 4-17). The Company stated that, compared to the technology alternatives, the proposed project has the highest projected availability factor, 92 percent, and lowest heat rate, less than 7,000 Btu/kWh[99] (id. at att. 4-2) (see Table 11, Section II.B.4.a,

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98 The Siting Board notes that the Department has proposed a series of market-based approaches to ensuring that renewable resources have a meaningful opportunity to compete in a restructured electric industry. Electric Restructuring Order Commencing Notice of Inquiry (NOI)/Rulemaking at 68-78. In particular, the Department has proposed a renewables fund, to be collected through a low, non-bypassable charge on distribution services, that could offset a portion of the difference between the price of power from a renewable energy source and the price that customers are willing to pay. Id. at 69.

99 The Company considers the heat rate of the proposed project to be confidential. For purposes of the technology comparison, the Company assumed a heat rate for the proposed project of 6,977 BTU/kWh (Exh. BP-1A at att. 4-2).

below).

a. Air Quality

The Company asserted that the proposed project would be preferable to all five alternative technologies with respect to air quality (Company Brief at 63). In support of its assertion, BPD provided an analysis of the average annual emission rates and the annual amount of emissions of sulfur dioxide ("SO_2"), NOx, PM-10, CO, VOCs and CO_2 for the proposed project and the technology alternatives (Exh. HO-RR-10). 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[100] (id.). The Company also assumed that the GTCC alternative would meet the same emissions control standards as the proposed facility and thus, would have the same emission rates as the proposed project (Exh. BP-1A at 4-19).

In reviewing the coal-fired technology alternatives, the Company assumed that the AFBC and IGCC alternatives would use high sulfur coal, the PC alternative would use low sulfur coal, and that average annual emissions rates would reflect Lowest Achievable Emission Rate ("LAER") technologies (id. at 4-5 to 4-7, 4-19).

BPD stated that the annual emissions of the proposed project would be substantially lower than the annual emissions from the coal-fired alternatives with two exceptions: (1) PM-10 emissions would be lower for the IGCC alternative[101] and (2) VOC emissions would be lower for the PC alternative (Exh. HO-RR-10). BPD further stated that, although the average annual emission rates of the proposed project and the GTCC are comparable, the annual emissions of the proposed project would be lower, reflecting its lower heat rate (Exh. BP-1A at 4-19). See

100 The Company's pending air permit application is based on use of back-up oil for a maximum of 720 hours per year (Exh. HO-E-26(att.) at 1-1).

101 The Company stated that if a CO catalyst were assumed for the IGCC alternative, PM-10 emissions of the IGCC alternative would be at least as high, or higher, than the PM-10 emissions of the proposed project (Exh. HO-RR-10; Tr. 3, at 27).

Table 10.

Table 10

ALTERNATIVE TECHNOLOGIES - POLLUTANT EMISSIONS

	BPD	GTCC	AFBC	PFBC	IGCC	PC
Ann. average emission rates (lbs/MMBTU)						
SO_2	0.0098	0.0099	0.225	0.225	0.078	0.2
NOx	0.0145	0.0146	0.15	0.15	0.035	0.17
PM-10	0.0183	0.0185	0.018	0.018	0.013	0.018
CO	0.0090	0.0090	0.13	0.13	0.056	0.11
VOC	0.0054	0.0054	0.006	0.006	0.007	0.0036
CO_2	117	117	204	204	204	204
Ann. emissions (tpy), based on assumed availability factor						
Availability Factor	92.0%	88.9%	90.4%	80.8%	85.7%	85.5%
SO_2	69	70	1,594	1,594	553	1,417
NOx	103	105	1,466	1,198	268	1,543
PM-10	130	132	176	144	99	163
CO	64	64	1,271	1,039	429	998
VOC	38	39	59	48	54	33
CO_2 (1,000 tpy)	827	837	1,994	1,630	1,561	1,852

Source: Exh. HO-RR-10

The record demonstrates that, on balance, considering all pollutants, the annual emissions of the proposed project would be lower that those of all of the 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 AFBC, PFBC, IGCC 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 (Company Brief at 64-65).

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. BP-1A at 2-2, 4-20). The Company stated that, assuming an 85 MW steam turbine, both the proposed project and GTCC alternative would require 1.392 million gallons per day ("mgd") for cooling tower makeup and 0.084 mgd for process water, including water for steam injection during oil firing, for a total water requirement of 1.476 mgd (Exh. HO-RR-10). The Company stated that, again assuming an 85 MW steam turbine, the IGCC alternative also would require 1.392 mgd for cooling tower makeup, but that a greater amount of process water, 0.654 mgd, would be required for the coal slurry makeup and continuous water injection for NOx control, for a total water requirement of 2.046 mgd (id.; Exh. BP-1A at 4-20 to 4-21). BPD stated that the AFBC, PFBC and PC alternatives each would have greater requirements for cooling tower makeup and process water than the proposed project, in amounts totalling: (1) 4.278 mgd for the AFBC alternative; (2) 3.429 mgd for the PFBC; and (3) 4.468 mgd for the PC alternative (Exh. HO-RR-10).

BPD stated that the proposed project and the GTCC alternative each would generate 0.135 mgd of cooling tower blowdown and 0.052 mgd of process wastewater, for a total of 0.187 mgd of wastewater (id.). In addition, BPD stated that the IGCC would generate the same amount of cooling tower blowdown, but would generate a greater amount, 0.323 mgd, of process wastewater, for a total of 0.458 mgd of wastewater (id.). The Company stated that the AFBC, PFBC and PC alternatives also would generate greater amounts of wastewater than the proposed project, in amounts totalling: (1) 0.542 mgd for the AFBC alternative; (2) 0.435 mgd for the PFBC alternative; and (3) 0.587 mgd for the PC alternative (id.).

The record demonstrates that the water requirements of the proposed project would be equivalent to those of the GTCC alternative and would be approximately: (1) 35 percent of the AFBC alternative's; (2) 43 percent of the PFBC alternative's; (3) 72 percent of the IGCC alternative's; and (4) 33 percent of the PC alternative's. Accordingly, the Siting Board finds that, for purposes of this review, the proposed project is comparable to the GTCC alternative and preferable to the AFBC, PFBC, IGCC 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: (1) 35 percent of the AFBC alternative's; (2) 54 percent of the PFBC alternative's; (3) 41 percent of IGCC alternative's; and (4) 32 percent of the PC alternative's. Accordingly, the Siting Board finds that, for purposes of this review, the proposed project is comparable to the GTCC alternative and preferable to the AFBC, PFBC, IGCC 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 AFBC, PFBC, IGCC and PC alternatives with respect to noise impacts (Company Brief at 65-66). Mr. Keast stated that major exterior noise sources at the proposed project would include the intake and exhaust from the combustion turbine, the cooling tower, ventilation openings in the turbine building wall, an exhaust duct, and the HRSG (Exh. BP-DK-3, at 1). Mr. Keast added that the major interior noise sources would include the gas and steam turbine-generators and ancillary equipment (id.).

In comparing the noise impacts of the proposed project to that of the technology alternatives, BPD 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. BP-1A at 4-21 to 4-22).[102] However, BPD stated that the coal-fired alternatives would

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[102] The Company noted that the AFBC, PFBC and PC alternatives would require larger cooling towers than the proposed project and that cooling tower noise mitigation

have added sources of noise due to coal usage (Exh. HO-RR-38). BPD stated that on-site noise due to coal delivery, including unloading, 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 (id.). BPD also stated that the gasification component and flare stack of the IGCC alternative would be additional on-site noise sources, and that it might not be possible to mitigate on-site noise of this alternative to the level of the proposed project (id.).

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 AFBC, PFBC and PC alternatives technically could be mitigated to the same degree, the coal delivery to the site would increase noise impacts of the AFBC, PFBC and PC alternatives relative to the proposed project. The record also demonstrates that the noise impacts of the IGCC alternative are potentially greater than the noise impacts of the other coal-fired alternatives.

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 AFBC, PFBC, IGCC and PC alternatives with respect to noise impacts.

d. Fuel Transportation

BPD asserted that the proposed project is slightly preferable to the GTCC alternative and far superior to the coal-fired alternatives with respect to fuel transportation impacts (id. at 4-22 to 4-23; Company Brief at 67). BPD stated that natural gas would be delivered to the site via a new pipeline that would be constructed within public ways and on-site, extending approximately 4,000 feet from the existing Tennessee mainline to the site (Exh. BP-1A at 2-5, 4-22). In addition, the Company asserted that back-up fuel oil delivery would not be a significant factor in the overall fuel delivery to the proposed project (id. at 4-22). BPD

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therefore would be more extensive for these alternatives (Exh. HO-RR-38).

explained that the proposed project would require a maximum of 991 oil trucks per year, or 33 oil trucks per day for 30 days per year, and that fuel oil deliveries would not exceed a maximum of two deliveries per hour (id.; Exh. HO-RR-10).[103] 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 (Exh. BP-1A at 4-22 to 4-23).

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, and noted that a coal-fired facility likely would be sited in close proximity to existing rail lines with adequate capacity to accommodate coal deliveries (id. at 4-24). Therefore, the Company stated that a coal-fired alternative was not a good match for the proposed site due to the lack of existing rail infrastructure at or near the site (id. at 4-23; Exh. HO-RR-10).

However, BPD stated that if a rail route to the proposed site could be identified, construction of a rail connection to the site from the closest existing rail mainlines likely would impact waterways, roadways and residences (Exh. HO-RR-10). The Company stated that the annual number of coal trains required for the coal-fired alternatives, assuming a 100 car unit train, would be approximately: (1) 78 for the AFBC alternative; (2) 64 for the PFBC alternative; (3) 61 for the IGCC alternative; and (4) 72 for the PC alternative (Exh. BP-1A at att. 4-4).[104] The Company stated that the AFBC, PFBC and PC alternatives also would require truck delivery of limestone or lime for SO_2 control amounting to approximately thirteen truck deliveries per day, five days per week, and that the IGCC alternative would likely require a

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103 BPD stated that the proposed project will include an on-site fuel storage tank, sized to store sufficient oil for three days of continuous operation, and noted that it was unlikely that gas would be unavailable for three continuous days (Exh. BP-1A at 4-22). In its pending air permit application, BPD indicated that it expects periods of oil-fired operation would not total more than 100 hours or less in most years (Exh. HO-E-26(att.) at 4-1 to 4-2).

104 BPD stated that if coal were delivered to the site by truck instead of rail, the coal-fired alternatives would require between 98 and 120 trucks per day, or 30,000 to 40,000 trucks per year (Exh. HO-RR-10).

natural gas pipeline for backup fuel (id. at 4-23).

The Company asserted that the overall impacts associated with fuel transportation for the coal-fired alternatives would be greater than those associated with fuel transportation for the proposed project (id.). The Company explained 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 and also would present the possibility of accidents (id.).

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 limited pipeline expansion and overall minimal impacts associated with fuel transportation for the proposed project, rail transport of coal likely would result in greater impacts.

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

e. Land Use

BPD 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 (Company Brief at 67). BPD stated that it evaluated total land requirements and surrounding uses to determine the land use impacts of the proposed project and its alternatives (Exh. BP-1A at 4-25). The Company also stated that the footprint of the proposed project would fit within ten acres of the undeveloped 40-acre site and that the height of the main components would be: (1) 67 feet for the boiler building; (2) 125 feet for the stack;[105] and (3) 50 feet for the cooling tower (Exh. BP-FS-2, at 2-8). The Company stated that the proposed site is located in an industrially zoned area, surrounded by industrial, commercial and residential uses (id. at 2-6).

BPD stated that the GTCC alternative could be designed to fit within the ten-acre footprint of the proposed project and that the height and size of the facility components would be comparable to the proposed project (Exh. BP-1A at 4-25). However, BPD stated that the coal-fired alternatives would require a greater amount of land for facility footprint, rail unloading and fuel storage areas, totalling: (1) 43 acres for the AFBC and PFBC alternatives; (2) 50 acres for the IGCC alternative; and (3) 49 acres for the PC alternative (id.). BPD stated that, in addition, the coal-fired alternatives would require a greater number of structures than the proposed project[106] 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.). However, the Company noted that land use impacts are extremely site-specific and that the coal-fired alternatives generally would be located at larger sites with significantly greater buffer areas.

The record demonstrates that the footprint of the proposed project and GTCC

105 BPD indicated that it has requested that the Massachusetts Department of Environmental Protection ("MDEP") approve a stack height of 125 feet (Exh. HO-E-1, att. at 2-1).

106 The Company stated that each of the coal-fired alternatives would require structures for coal unloading and handling and that the IGCC alternative also would require a gasification plant and flare stack (Exh. BP-1A at 4-25 to 4-26).

alternative would require ten acres within the proposed 40-acre site. The record further demonstrates that the coal-fired alternatives would have footprints of between 34 to 50 acres and would require a greater number of buildings and larger scale buildings than the proposed project. The Siting Board notes that each of the coal-fired alternatives likely could be constructed on the proposed site if available adjacent land were purchased but that a coal-fired alternative likely would be constructed on a larger site, providing a greater buffer between the facility buildings and surrounding uses.

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 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 AFBC, PFBC, IGCC, 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 (Company Brief at 68). In support thereof, BPD stated that the proposed project and the GTCC alternative would generate minimal amounts of solid waste, approximately 250 tpy, consisting primarily of incidental office and maintenance waste (Exh. BP-1A at 4-26, and att. 4-6). In contrast, the Company stated that the solid waste generated by the coal-fired alternatives, consisting primarily of ash for the AFBC, PFBC and PC alternatives and slag for the IGCC alternative, would total: (1) 183,000 tpy for the AFBC alternative; (2) 149,500 tpy for the PFBC alternative; (3) 62,000 tpy for the IGCC alternative; and (4) 136,400 tpy for the PC alternative (id.). The Company added 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 (id. at 4-26).

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. 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 AFBC, PFBC, IGCC 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 AFBC alternative, the PFBC alternative, the IGCC alternative and the PC alternative 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 AFBC alternative, the PFBC alternative, the IGCC alternative and the PC alternative with respect to environmental impacts.

4. Cost

a. Description

BPD asserted that the proposed project would be clearly superior to each of the technology alternatives with respect to cost (Company Brief at 62). In order to compare costs, the Company explained that it modelled the projected total revenue requirements of each of the alternatives over a 20-year period, with an assumed in-service date of January 1, 1999 (Exh. BP-1A at 4-15).[107] 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.).

The Company indicated that the initial cost and performance data for the proposed project were consistent with the Company's pro forma, and initial cost and performance data for the technology alternatives were based on the 1993 TAG report (id.).[108] BPD stated that inflation rates were taken from the 1994 GTF report (id. at att. 4-1). With respect to fuel prices, the Company indicated that the initial fuel price for the proposed project was based on actual quotes and was escalated at five percent annually and that the initial fuel prices for the technology alternatives and escalation rates were obtained from the 1994 GTF report (id., att. 4-1, 4-17; Exh. HO-A-10). BPD stated that it also assumed that the proposed project and the technology alternatives would run constantly, limited only by their availability factors (Exh. BP-1A at 4-16).

Table 11, details the total installed costs,[109] O&M costs, and 20-year levelized costs for

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[107] In projecting total revenue requirements for each alternative, BPD used consistent assumptions with respect to cost of debt, cost of capital, tax rate, and depreciation (Exh. BP-1A at 4-1).

[108] The Company also calculated the cost of the coal-fired alternatives with lower land costs (Exh. HO-RR-20). The Company indicated that lower land costs made little difference in levelized costs (id.).

[109] The Company indicated that total installed cost includes total cost of plant, permitting, land, interconnection, allowance for funds during construction, startup and inventory, and working capital (Exh. BP-1A at 4-2).

the technology alternatives. The Company indicated that the 20-year levelized cost of the proposed project would be significantly lower than the 20-year levelized cost of each of the technology alternatives (Exh. BP-1A at 4-17; see also, Exh. HO-A-11).[110]

Table 11

TECHNOLOGY PARAMETERS AND LEVELIZED COSTS

	BPD	GTCC	AFBC	PFBC	IGCC	PC
Size (MW)	252	252	252	252	252	252
1994 Fuel Price ($/MMBTU)		$2.95	$1.55	$1.55	$1.55	$1.70
Availability Factor	92.0%	88.9%	90.4%	80.8%	85.7%	85.5%
Heat Rate (BTU/kWh)	6,977	7,300	9,796	8,959	8,090	9,618
Total Installed Cost ($1999/kW)		$804	$2,253	$1,868	$2,410	$2,295
Fixed O&M ($1999/kW)		$32.83	$46.73	$53.55	$60.80	$67.44
Var. O&M ($1999/kW)		$0.51	$6.82	$4.17	$0.63	$2.88
20-yr Nominal Levelized Cost ($/kWh)	*	$0.071	$0.084	$0.088	$0.090	$0.097

* The 20-year nominal levelized cost for the proposed project was less than $0.071/kWh.

Sources: Exhs. BP-1A, atts. 4-2, 4-3; HO-A-11.

b. Analysis

The record indicates that the 20-year levelized cost of the proposed project would be less than the 20-year levelized cost of each of the technology alternatives, given the Company's assumptions regarding capital costs, interest rates, and fuel prices. The Siting Board notes that the Company's analysis does not provide for future uncertainty in fuel price forecasts. An analysis of the sensitivity of the cost comparisons to changes in fuel prices would have been

110 The fuel price, total installed cost, O&M costs, and levelized cost for the proposed project were provided in confidential documents.

particularly relevant in this case, since there is no fuel contract for the proposed project.

In addition, the Siting Board notes that the Company's cost analysis was based on 20-year levelized cost, and did not include cost estimates over a longer project life of 25 or 30 years. Such a comparison would be more favorable to the more capital-intensive technology alternatives. Given that the costs of a generating facility are likely to be spread over a 30-year or longer period rather than a 20-year period, and that the capital costs of the coal-fired alternatives are higher than the proposed project, the Siting Board recognizes that the use of a 30-year levelized cost could decrease the cost of the coal-fired alternatives relative to the proposed project. See Cabot Decision, 2 DOMSB at 351; EEC (remand) Decision, 1 DOMSB at 375. However, given the significant 20-year levelized cost advantage of the proposed project over the coal-fired alternatives, it is unlikely that a 30-year cost analysis would reverse the relative cost superiority of the proposed project over the coal-fired alternatives.

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

5. Reliability

a. Description

The Company asserted that the proposed project is preferable to each of the alternative technologies with respect to reliability (Company Brief at 68). In assessing 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 and would operate in accordance with the cost and performance specifications at the time when the first need for new capacity has been identified (Exh. BP-1A at 4-27 to 4-28).

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 not been fully demonstrated and are based primarily on engineering estimates (id. at 4-28). The Company reported that the combined cycle technology and PC technology are categorized as mature in the 1993 TAG report, giving the proposed project, the GTCC alternative and the PC alternative a reliability advantage over the other technology alternatives under consideration (id.). The Company stated that the proposed project would have an anticipated availability of 92 percent, higher than any of the other technology alternatives (see Table 11, above) (id. at 4-27). In addition, the Company stated that it anticipates securing a firm fuel transportation contract from a point in New York to the proposed project and that, at the option of customers, BPD would arrange for a gas supply or allow the power purchaser to contract for its own gas supply (Exh. HO-RN-57; Tr. 2, at 10-11). See Section II.C.3.b, below. Thus, the Company concluded that the proposed project is superior to the technology alternatives with respect to reliability (Exh. BP-1A at 4-27).

b. Analysis

The record demonstrates that the availability of the proposed project would be 92 percent and that the technology of the proposed project is classified as mature by the 1993 TAG report. Although the Company has indicated that the proposed project would have a firm transportation contract, the Siting Board notes that the Company has not as yet contracted for firm pipeline transportation, and has indicated that it may consider a contract that is firm for less than 365 days per year. However, the Company 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, 3.1 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 difference for the purposes of this review. In addition, the GTCC technology is classified as mature by the 1993 TAG report. 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 AFBC alternative, the Siting Board notes that the availability factor for the AFBC alternative is assumed to be 90.4 percent, 1.6 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 AFBC alternative, does not represent a significant difference for the purposes of this review. However, the proposed project is classified as a mature technology, denoting significant operating experience, while the AFBC 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 AFBC alternative with respect to reliability.

In comparing the reliability of the proposed project to that of the PFBC alternative, the Siting Board notes that the availability factor of the PFBC alternative is assumed to be 80.8 percent, 11.2 percent less than that of the proposed project. This difference in availability between the two technologies is significant when considered in conjunction with the difference in maturity level of the two technologies. While the proposed project is classified as a mature technology, the PFBC technology is classified as a demonstration technology, which indicates that the PFBC technology it is not yet considered a commercial technology. Accordingly, the Siting Board finds that the proposed project would be preferable to the PFBC alternative with respect to reliability.

In comparing the reliability of the proposed project to that of the IGCC alternative, the Siting Board notes that the availability factor of the IGCC alternative is assumed to be 85.7 percent, 6.3 percent less than that of the proposed project. This difference in availability between the two technologies is significant when considered in conjunction with the difference in maturity level of the two technologies. While the proposed project is classified as a mature technology, the IGCC technology is classified as a demonstration technology, which indicates that the IGCC technology it is not yet considered a commercial technology. Accordingly, the Siting Board finds that the proposed project would be preferable to the IGCC 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, 6.5 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 AFBC, PFBC and IGCC alternatives 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 alternate approaches in the 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 AFBC, PFBC, IGCC, and PC alternatives with respect to environmental impacts; (2) preferable to the GTCC, AFBC, PFBC, IGCC, and PC alternatives with respect to costs; and (3) comparable to the GTCC and PC alternatives and preferable to the AFBC, PFBC, and IGCC alternatives with respect to reliability.

Accordingly, the Siting Board finds that the proposed project is superior to the GTCC alternative, the AFBC alternative, the PFBC alternative, the IGCC 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

The Siting Board determines that a proposed non-utility generating project 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 life of its power sales agreements. Cabot Power Decision, 2 DOMSB at 364, 370; Altresco Lynn Decision, 2 DOMSB at 144, 152; NEA Decision, 16 DOMSC at 380.

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 frames 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 terms of the power sales agreements. Cabot Power Decision, 2 DOMSB at 358; Altresco Lynn Decision, 2 DOMSB at 136-152; NEA Decision, 16 DOMSC at 378-380.

Here, BPD has argued that the project fully meets each of the Siting Board's viability tests, and that the proposed project will be a viable source of energy (Exh. BP-1A at 5-1).

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. BPD asserted that a number of factors -- the project's low cost and low environmental impacts, the successful experience of the developers, 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 (Exhs. HO-V-4; HO-V-6).

BPD asserted that its development team, comprised of PDC, ABB EV and CSC, in association with its project management team, have extensive experience in energy project development, power plant design and construction, and power plant operation (Exh. BP-1A at 1-5). With regard to development and financing experience, the Company reported that the principals of PDC and CSC have been directly involved in three Massachusetts projects (the Altresco-Pittsfield project, the Altresco Lynn project, and the TEC), and one project in China (Exh. HO-V-2). Further, BPD stated that ABB operates in more than 140 countries and is ranked 38th in the Global Fortune 500, with extensive experience in gas-fired combined cycle facilities in the United States totaling approximately 2,334 MW of capacity (id.; Exh. BP-1A at 1-6). The Company stated that ABB EV would provide development and equity funding for the project, as well as general project oversight (Exh. BPD-1A at 1-6). In addition, the company stated that R.W. Beck, the owners' engineer, has been involved in over 350 project-finance projects, both in the United States and abroad (Exh. BP-RC-1, at 5; Tr. 1, at 45). The Company's witness stated that R.W. Beck has experience in engineering, commercial, financial and contractual issues, all of which are necessary to the successful financing of a project (Tr. 1, at 46).

BPD stated that its preferred financing strategy is based on executing long-term contracts under conventional financing (Exh. HO-V-4). BPD explained that projections of the costs and revenues of a project are made based on binding contracts which specify such costs and secure such revenues (Exh. HO-V-5). To demonstrate financiability under conventional financing, the Company provided two pro forma analyses: a base case that assumes 100 percent of the project's capacity is sold under long term contracts, and a low case that assumes 75 percent of the capacity is sold (Exh. HO-V-4(rev)).[111] The Company asserted that the debt coverage ratios ("DCR") in both pro formas are sufficient to achieve financing (id.).[112] Mr. Cotte stated that in a typical project financing, a reasonable DCR average value is 1.25; however, he stressed that lenders consider factors other than DCRs when making financing decisions and that there is no industry-standard minimum DCR (Tr. 1, at 62).

The Company indicated that it also assessed its financiability under a "merchant plant" financing scenario/approach, which assumes no long-term PPAs (id. at 62, 81). The Company explained that the term "merchant plant" financing describes a situation involving unsecured or market risk resulting from uncertainty about the revenue stream necessary to amortize the debt repayment (Exh. HO-V-5). BPD indicated that in assessing financiability under a merchant plant scenario, it is more appropriate to consider return on equity than DCRs, because the focus of an investor's assessment of the success of the project is based on the rate of equity return, which is a function of the future market price of electricity (Exh. HO-V-4). Although the equity component required for merchant plant financing, which BPD estimates to be 55 percent, is much larger than that required for conventional financing, BPD indicated that it is confident of its ability to obtain the necessary equity (Tr. 1, at 16, 72, 92).[113]

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111 The Company-sponsored pro formas detailed average debt coverage ratios of 1.84 for the base case and 1.38 for the low case (Exh. HO-V-4(rev); Tr. 1, at 66).

112 The Company stated that it conservatively assumed that under the low capacity scenario all capacity not sold under long-term contract would be sold at 1.5 cents/kWh (Exh. HO-V-4; Tr. 1, at 68).

113 The Company listed a variety of possible sources of equity, including commercial lenders, large insurance companies, equity investment funds, and vendors such as fuel suppliers and contractors (Tr. 1, at 50). BPD stated that ABB, which the Company indicated is a global organization of which ABB EV is a part, and ABB EV are willing to commit equity to the proposed project (id. at 50-51).

The Company's witness asserted that although no independent power producer ("IPP") has yet been financed using the merchant plant approach, the financial marketplace has been anticipating the use of merchant plant financing for IPPs for the past two years (id. at 78). The Company acknowledged that merchant plant financing has higher financing costs than conventional financing, since the cost of capital is higher due to the larger proportion of equity needed (id. at 58). The Company asserted that the proposed project can absorb the extra financing costs and still be competitive due to the low cost of the proposed facility (id.). Further, BPD asserted that the proposed plant, even if financed as a merchant plant, would be far less expensive than nearly all existing generation facilities (Exh. HO-V-4).

Finally, the Company stated that it is using an innovative marketing strategy based on its issuance of a Reverse Request for Proposals ("RFP") in June of 1995 -- an RFP in which the Company solicited expressions of interest to buy capacity and associated energy from the proposed project (Exhs. HO-V-7; HO-RN-41, at I-1). The Company stated that the responses it received to the reverse RFP exceeded the capacity of the facility, that the responses included a range of offers concerning fuel supply options, and that interest was expressed in equity participation (Tr. 1, at 11-12). BPD's witness asserted that, based on the responses to the reverse RFP, there is enough demand for the proposed project on a conventional project finance basis to go forward with typical project financing (id. at 75-76).

The record indicates that the project proponents have a broad range of experience in overall project development, including financing. The principals of PDC have developed three IPP's that have been approved by the Siting Board. In addition, ABB EV has substantial worldwide experience in the power development field, as well as significant capital resources. Further, R.W. Beck is knowledgeable, and has arranged for both conventional financings for IPPs and other types of energy projects and merchant plant financings for energy projects other than IPPs.

The range of assumptions provided by BPD in its pro formas is generally reasonable and consistent with Siting Board reviews in prior proceedings. The Company's pro formas indicate that the BPD project is financiable based on projections of DCRs for differing levels of capacity sold under long-term power sales under conventional financing. In addition, ABB EV has indicated that it would contribute to the equity needed to finance the proposed facility.

The Siting Board notes that BPD does not have any signed contracts for its output. However, BPD has presented an alternative financing approach in the event that long-term contracts are not signed by financial closing. 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 stated that it can produce electricity at a competitive rate. The Siting Board notes that although the Company has reported that the response to its reverse RFP exceeded the capacity of the proposed project, the Siting Board must consider the possible attrition of respondents as the proposed project develops. However, the level of positive responses to the reverse RFP provides an early indication of the level of interest in the proposed facilities's output.

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

b. Construction

In considering a proponent's construction strategy for a proposed project, the Siting Board considers whether the project is reasonably likely to be constructed and go into service as planned. Here, BPD indicated that it has negotiated a turnkey construction contract ("EPC turnkey contract") with a construction consortium comprised of ABB Power Generation and Black and Veatch Construction, Inc. ("B&V") (Exh. BP-1A at 5-2). B&V would be the engineering, procurement, and construction ("EPC") contractor and ABB Power Generation, affiliated with ABB EV, would be the equipment supplier for the project and a partner to the EPC contractor (id. at 1-7, 1-9).

BPD asserted that B&V is a world leader in combustion turbine power plant projects with extensive experience as design engineer, construction manager, owner's engineer, and financial institution's engineer (Exhs. HO-V-14; BP-1A at 1-9, 1-10). The Company provided information demonstrating that B&V has completed work on more than 20 combined cycle projects in the last ten years, and is slated to complete over 15 more in the next five years, ranging in capacity from 116 MW to 1,350 MW (Exh. HO-V-14). The Company stated that B&V was the lead architect in the development of the ABB GT-24 ACS Combined Turbine Generator ("GT-24") plant (Exh. BP-1A at 1-9). BPD stated that ABB Power Generation is part of a global ABB organization that provides the power industry with power generation, transmission and distribution equipment (id. at 1-8). The Company provided information which indicated that ABB Power Generation has over 1,000 utility and industrial installations using gas turbine and combined cycle systems throughout the world (id. at (att.) 2-1). In addition, ABB Power Generation developed the first dry low-NOx combustor in 1984 (id. at (att.) 2-4).

The Company has submitted a Term Sheet, which is the basis for negotiation of the final EPC turnkey contract, that provides the owner with a fixed price for the proposed project based on an agreed scope of work (id. at 5-3; Exh. HO-V-13, (att.) a(red.)). BPD stated that, according to the Term Sheet, B&V would be responsible for all design, engineering, procurement, manufacturing, delivery, construction tasks and installation needed to bring the plant into operation at guaranteed output, heat emissions, noise and other performance levels (Exh. BP-1A at 5-3). The Term Sheet, as a precursor to the EPC turnkey contract, contains a set of binding terms and conditions for the engineering and construction of the proposed BPD facility, including provisions for: (1) a lump sum price; (2) a guaranteed schedule; (3) liquidated damages for failure to achieve (a) substantial completion by the guaranteed completion date and (b) operation guarantees; (4) an early completion bonus; (5) warranties; (6) insurance; and (7) acceptance testing (Exh. HO-V-13, att. a (red.)).

The Company indicated that the first GT-24 is scheduled to undergo nine months of testing in the spring of 1996, and is scheduled for commercial operation in the summer of 1997 at the Gilbert Generating Station in New Jersey (Exhs. HO-V-14; HO-RR-51).[114] The

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[114] The Company indicated that, in addition to the Gilbert facility, ABB will also have a GT-24 operating in Korea at the time of BPD's commercial operation, and the GT-26, which is a scaled version of the GT-24, will be operating in Switzerland, Germany and England (Exh. HO-RR-49). The Company also indicated that the GT-24 is being considered for nine other projects (Exh. HO-RR-50).

Company stated that the testing of the GT-24 at the Gilbert facility is proceeding as scheduled and that it has not experienced any problems that would affect the ability of the GT-24 to operate as planned (Tr. 1, at 15). BPD indicated that the first GT-24 will have completed approximately three years of operation prior to the commercial operation date for the BPD facility (Exh. HO-V-11). Finally, the Company stated that ABB is not aware of any other gas turbine available in the marketplace that could achieve the performance and emission profiles of the GT-24 (Exh. HO-RR-52). Nevertheless, the Company asserted that ABB has guaranteed the plant's performance and is required to correct any problems or pay liquidated damages (id.).

The Company stated that interconnection to the regional electric transmission grid would be via a 115 kV transmission line which would extend approximately 500 feet across the northern portion of the site, connecting to an existing 115 kV WMECo transmission line (Exh. BP-1A at 2-5). BPD stated that R.W. Beck conducted a detailed interconnection analysis based on load flow studies, which concluded on a preliminary basis that the proposed facility could be reliably interconnected with the existing 115 kV transmission system with limited reconducturing (Exh. HO-V-19). The Company indicated that it will be preparing studies that address additional contingencies, as directed by Northeast Utilities ("NU"),[115] and noted that NU was supportive of the project in preliminary meetings based on BPD's initial interconnection and load flow analysis (Tr. 1, at 28-30). BPD's witness stated that, because NU requires a significant deposit before entering into contractual discussions for a final interconnection agreement, the Company would not execute a final contractual agreement with NU until later in the permitting schedule of the project (id.).

The Company provided a letter from the Agawam Superintendent of Public Works that noted the ability of the Town to provide water to the proposed project (Exh. BP-1B at 7-62, (att.) 7.3.1). The Company also stated that option agreements exist between BPD and the owners of the two individual parcels that comprise the proposed project site (Tr. 4, at 17).

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115 WEMCo is a subsidiary of Northeastern Utilities.

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 likely to be constructed on schedule and will be able to perform as expected. Cabot Power Decision, 2 DOMSB at 363; Altresco Lynn Decision, 2 DOMSB at 143; Altresco-Pittsfield Decision, 17 DOMSC at 380. Here, BPD has submitted a Term Sheet, the precursor to a final EPC turnkey contract. In addition, the record in this proceeding indicates that B&V and ABB Power Generation have significant experience in the design and construction of plants which use the technology proposed for this project and have successfully completed similar projects.

The Siting Board notes however, that the proposed gas turbine technology, the GT-24, is as yet unproven in commercial operation. While the Company has asserted that the equipment has passed each milestone to date, and that ABB would be responsible for correcting any problems or incur stiff financial penalties, the proposed project cannot go forward as planned if unexpected problems develop with the GT-24. Specifically, the project could miss significant construction milestones, which would delay financial closing, or could fail to meet stringent operating criteria such as the expected low heat rate and low emission rates. The Siting Board notes 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.). The Siting Board notes that should the GT-24 be unable to perform substantially as expected, this would constitute a change to the proposed project such that the Company would be required to notify the Siting Board as explained in Section IV, below.

The Siting Board notes that the Term Sheet includes a number of advantageous provisions, such as incentive and penalty terms, which the Siting Board has recognized in previous reviews as ensuring timely and quality construction projects. If the final EPC turnkey contract contains all of the significant provisions included in the Term Sheet, BPD will be able to establish that the proposed project is likely to be constructed within the applicable time frames and be capable of meeting performance objectives. Therefore, the Siting Board requires BPD to provide the Siting Board with a copy of a signed EPC turnkey contract between BPD and B&V/ABB Power Generation that is identical or similar in all significant provisions to the

Term Sheet, as evidence of a reasonable assurance that the project is likely to be constructed on schedule and will be able to perform as expected.

While BPD has been in contact with NU and has prepared an interconnection and load flow study, BPD has not entered into a signed interconnection agreement with NU enabling transmission access. Failure to gain access to the regional transmission system would prevent the proposed project from providing energy to the state and the region. However, if BPD provides a signed interconnection agreement, BPD will be able to establish that its proposed project is likely to be capable of being dispatched as expected. Therefore, the Siting Board requires BPD to provide the Siting Board with a copy of a signed interconnection agreement between BPD and NU.

Accordingly, upon compliance with the above conditions that the Company provide the Siting Board with (1) a copy of a signed EPC turnkey contract between BPD and B&V/ABB Power Generation that is identical or similar in all significant provisions to the Term Sheet, and (2) a copy of a signed interconnection agreement between BPD and NU providing the proposed project with access to the regional transmission system, the Siting Board finds that BPD 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 BPD has established that its proposed project is likely to be financiable. The Siting Board also has 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, BPD will have established that its proposed project is likely to be constructed within applicable time frames and capable of meeting BPD performance objectives. Accordingly, the Siting Board finds that, upon compliance with the above conditions, BPD 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 non-utility generation project is likely to be viable as a reliable, least-cost source of energy over the life of its power sales agreements, the Siting Board evaluates the ability of the project proponent or other reasonable entities to operate and maintain the facility in a manner which ensures a reliable energy supply. Cabot Power Decision, 2 DOMSB at 364-366; Altresco Lynn Decision, 2 DOMSB at 145-146; 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 must establish that experienced and competent entities are contracted for, or otherwise committed to, the performance of critical tasks. These tasks should be enumerated in detailed contracts or other agreements that include financial incentives and/or penalties which ensure reliable performance over the life of the power sales agreements. Cabot Power Decision, 2 DOMSB at 366-370; Altresco Lynn Decision, 2 DOMSB at 145-152; Altresco-Pittsfield Decision, 17 DOMSC at 382-383.

Here, BPD stated that it has selected ABB Operations and Maintenance Department ("ABB O&M") as its O&M contractor (Exh. BPD-1A at 1-7, 1-11). BPD provided a copy of a draft contract between BPD and ABB O&M for O&M services (Exh. HO-V-13, (att.) b (red)). The draft O&M contract contains a set of principal terms and conditions for the operation and maintenance of the proposed facility that encompass both the preliminary mobilization period and operation (id.). In addition, the agreement specifies performance targets for availability, heat rate, capacity, and budget variation, which are tied to an incentive fee (id. at 24).

The Company stated that ABB O&M has extensive experience in the operation of ABB combined cycle equipment, as well as experience providing O&M service for electric utilities (Exh. BPD-1A at 1-11). Specifically, BPD asserted that ABB O&M has over 100 years of experience with rotating equipment, including gas turbines and combined cycle equipment, and over 60 years of electric utility management experience (Exh. HO-V-14; Company Brief at 20). BPD provided information stating that ABB O&M is under contract to manage a total of approximately 4,350 MW, and currently operates eight combined cycle facilities (Exh. HO-V-14). BPD stated that there are significant advantages to ABB O&M operating the GT-24, since

ABB designed the GT-24 and is therefore extremely knowledgeable regarding the operation of the equipment (Tr. 1, at 19).

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 over the life of its power sales agreements. Cabot Power Decision, 2 DOMSB at 365; Altresco Lynn Decision, 2 DOMSB at 146; Altresco-Pittsfield Decision, 17 DOMSC at 382. Here, BPD has provided a draft O&M agreement with ABB O&M, a qualified vendor who is familiar with the turbine equipment, that includes bonus, penalty, and incentive provisions similar to those reviewed and approved in other Siting Board decisions. The agreement contains sufficient detail to demonstrate to the Siting Board that the project is likely to be operated and maintained in a manner consistent with reliable performance over its expected life if the agreement is signed. If BPD provides an executed O&M agreement, which is identical or similar in all significant provisions to the draft contract with ABB O&M, the Company will be able to establish that the proposed project is likely to be operated and maintained in a manner consistent with appropriate performance objectives. Therefore, the Siting Board requires BPD to provide the Siting Board with a copy of a signed O&M agreement between BPD and ABB O&M that is identical or similar in all significant provisions to the draft contract.

Accordingly, the Siting Board finds that, upon compliance with the above condition that BPD provide the Siting Board with a copy of a signed O&M agreement between BPD and ABB O&M that is identical or similar in all significant provisions to the draft contract, BPD will have 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 considers whether such a strategy reasonably ensures low-cost, reliable energy resources over the terms of its power sales agreements.

BPD asserted that it expects that in a more competitive environment, PPAs likely will be for terms of five to ten years, and that it therefore has developed a range of strategies to ensure reliable transportation and supply to the facility in accordance with the length of expected PPAs (Exh. BP-1A, at 5-6, 5-7). The Company's witness, Mr. Corbett, stated that he determined that the project must have firm transportation into New England (Tr. 2, at 10-11). Mr. Corbett selected the intersection of the Tennessee and the Iroquois Gas Pipeline Company ("Iroquois") system at Wright, New York ("Wright") as an appropriate delivery point from which to ensure firm transportation to the project site (id.).[116] Therefore, BPD determined that it would contract with Tennessee for firm transportation from Wright to the facility in Agawam, either for 365 days per year or for a lesser period of time such as 335 days (Exh. HO-V-16; Company Brief at 23).[117]

BPD stated that it anticipates securing a firm transportation contract in time for financial closing in late 1996 (Tr. 2, at 50). BPD indicated that a Tennessee compressor station is located approximately 4,000 feet south of the proposed primary site, and that Tennessee would construct a new 16-inch interconnection to the proposed facility (Exh. BP-FS-2, at 2-33). The Company asserted that Tennessee would be filing a proposal for the 4,000-feet interconnect with the FERC this year (Tr. 2, at 50).

BPD reported that Tennessee cannot determine at this time whether firm service to the proposed project would require upgrades to the system between Wright and Agawam. However, Tennessee indicated that the costs of any necessary upgrade could be accommodated within the existing tariff rates and would not require an incremental rate (Exh. BP-DC-3; Tr.

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116 BPD provided a letter from Tennessee which summarizes the status of discussions between BPD and Tennessee (see Exh. BP-DC-3). In addition to Wright, Tennessee presented a number of possible delivery point options including Morrisville, New York, Tennessee's northern storage fields, and the Gulf Coast, as well as downstream options such as the Distrigas of Massachusetts ("DOMAC") facility, and interconnects with the proposed Portland Pipeline Project or the proposed Sable Island Project (id.).

117 The Siting Board notes that Tennessee's letter does not specify either the level of firm transportation service that BPD has requested, or the level that Tennessee has guaranteed (see Exh. BP-DC-3).

2, at 17). BPD asserted that if it signs a contract with Tennessee, Tennessee would be responsible under such contract for transporting the gas from the Wright delivery point to the proposed facility at the designated start date under all circumstances, regardless of the timeframes for any upgrades (Tr. 2, at 19). BPD explained that Tennessee stated it has options for meeting this responsibility in the designated timeframe, such as purchasing gas from DOMAC or from storage-type projects (id.).

In keeping with its goal of flexibility, BPD stated that, at the option of its customers, it would arrange for a gas supply or allow the power purchaser to contract for its own gas supply (Exh. HO-RN-57). The Company explained that the project could also accommodate suppliers of natural gas who would deliver the gas to the proposed project for conversion into electricity (Exh. HO-RN-58). The supplier could then either sell the electricity itself, or have BPD sell the electricity for the supplier's account (id.).

The Company explained that, in its RFP, it offered power based on initial fuel costs for the project as quoted by suppliers for five, 10 and 20 year terms with varying escalator rates, ranging from zero to five percent (Exh. HO-A-10). The Company developed prices based on three options quotes, including: (1) supplies from the Gulf Coast delivered to the Tennessee system; (2) supplies from Alberta, Canada; and (3) supplies delivered at Wright, regardless of origin (Tr. 2, at 32-35). The Company asserted that it would be able to acquire gas supplies to meet the requirements of its PPAs, and that it would make a variety of price options available to its customers (Exh. BP-1A at 5-7). BPD asserted that by tailoring its gas supply purchases to the requirements of its customers, it would minimize cost while retaining flexibility (Company Brief at 25).

BPD stated that it obtained transportation rates and prices from Tennessee, Iroquois, CNG Transmission, and ANR Pipeline (Exh. HO-A-10). Further, BPD stated that recent gas supply developments in New England may provide the Company with secondary gas supply options, including capacity releases from local distribution companies, new pipeline projects such as the Portland Pipeline Project and Sable Island Project, and new sources such as the

DOMAC/Trinidad LNG Project (Exh. HO-V-15).[118] The Company asserted that two gas suppliers, Enron Gas Marketing and Natural Gas Clearinghouse, have indicated that they are capable of guaranteeing gas deliveries at Wright for 335 days per year (Exh. HO-V-16).

BPD stated that development of a fuel transportation and supply strategy, day-to-day management of the supply, and administration of the fuel transportation contracts would be the responsibility of Pendulum Gas Services ("Pendulum") (Exh. BP-1A at 1-10). BPD asserted that Pendulum can arrange for the flexible contract scheduling that BPD wishes to offer its clients, noting that Pendulum has had experience servicing multiple contracts through a single meter (Tr. 2, at 74). Further, the Company stated that Pendulum has handled daily nominations, contract administration, and asset management in New England (id. at 74).

In the event of a gas supply interruption, BPD indicated that it would use low sulfur (0.05 percent) No. 2 distillate fuel oil as a back-up fuel (Exh. BP-1A at 2-2). BPD's proposed air permit would allow it to burn low sulfur oil for thirty days each year (Exh. E- 26 (att.) at 4-1).[119] BPD stated that, if necessary, the proposed plant can operate on both gas and oil at different times during a day (id.; Tr. 2, at 72). The Company indicated that it would maintain a three-day supply of No. 2 fuel oil on-site in a nominal 930,000 gallon storage tank (Exh. BPD-1A at 2-2). The Company stated that it would contract with a qualified fuel oil supplier located in the greater Springfield area, to be selected based on its financial stability, on-site storage capacity, diversity of supply, quality control program, environmental and safety performance, and insurance requirements (Exh. HO-V-18).

In the past the Siting Board has viewed favorably gas-fired facilities that have provided

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118 The Company's witness indicated that the Sable Island Project was expected to be in service by the third quarter of 1999, that the DOMAC project was targeted for January 1999, and that he was not certain of the timeframe for the Portland Pipeline Project (Tr. 2, at 14).

119 The Company stated in its air permit application that, although it would be permitted to burn 30 days of oil, it expects that it would burn oil for 100 hours or less in most years (Exh. HO-E-26, at 4-1). Further, the Company's witness stated that he expects that the Company would burn oil for approximately 64 hours a year (Tr. 13, at 98).

signed gas supply and transportation contracts, or fuel supply options that were in advanced stages of completion. Cabot Decision, 2 DOMSB at 369; Altresco Lynn Decision, 2 DOMSB at 150; West Lynn Decision, 22 DOMSC at 72.[120] Such contracts generally have matched the length of the proposed project's power purchase agreements, which typically have been 20 years. However, the Siting Board notes that, given recent structural changes in the gas industry following the issuance of FERC Order 636, as well as the prospect of future structural changes in the electric industry, a different approach to the Siting Board's review of fuel acquisition may be appropriate.

The Siting Board recognizes 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. Nevertheless, the Siting Board must still be convinced that low-cost, reliable energy resources 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 our mandate. Demonstrating that proposed facilities will remain competitive and reliable over time not only provides important security in meeting long term energy needs, but also provides assurances that such facilities will be as fully utilized over their planned lives as possible, thereby helping to minimize the future need for additional new construction and its associated cost and environmental impact.

Accordingly, in applying its standard of review for viability relative to fuel acquisition, the Siting Board will henceforth consider whether an applicant's fuel acquisition strategy

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[120] The Siting Board notes that in the past three gas-fired facility cases, each proposed project has contracted for gas on a firm basis for 365 days per year. Cabot Decision, 2 DOMSB at 366; Altresco Lynn Decision, 2 DOMSB at 146; Enron Decision, 23 DOMSC at 108. The Siting Board further notes that the Altresco-Lynn facility was permitted for only five days of oil per year, and the Enron facility's back-up plans did not include oil-firing. Altresco Lynn Decision, 2 DOMSB at 149; Enron Decision, 23 DOMSC at 113-114. The West Lynn facility had a signed contract for gas on a firm basis for 330 days per year, and was permitted for 55 days of oil per year. West Lynn Decision, 22 DOMSC at 73, 92.

reasonably ensures a low cost, reliable source of energy over the planned life of the proposed project.

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. Cabot Power Decision, 2 DOMSB at 369-370; Altresco Lynn Decision, 2 DOMSB at 150-151; Altresco-Pittsfield Decision, 17 DOMSC at 384-389.

The Company has presented a fuel acquisition strategy that involves (1) the intent to contract for firm transportation from Wright, or a comparable location(s), for at least 335 days per year, and (2) a specific back-up supply plan, including a three day, on-site oil supply with the intent to contract for fuel oil from a supplier in the Springfield area, and the ability to switch to oil for limited operation.

BPD has acknowledged the possible capacity constraints in the New England region and the likelihood of interruptions in service in the region, and therefore has tentatively designated Wright as an upstream delivery point from which firm transportation to the proposed project would be guaranteed. However, it remains unclear whether BPD will contract for 365 days of firm transportation service, or a lesser amount such as 335 days. In fact, based on correspondence provided by BPD with Tennessee, Wright may not be the only designated delivery point from which firm transportation to the proposed facility could be contracted; another upstream location mentioned is Morrisville, New York, as well as Tennessee's northern storage fields. Additionally, in the event that BPD chooses to use one of its identified secondary supply sources, such as DOMAC or Sable Island, BPD may need to contract for a downstream delivery point and downstream transportation.

While BPD has not yet finalized its plans for acquiring firm transportation from a major interconnection point to its proposed site, it has indicated that it will do so in time for the financial closing. In addition, BPD has employed Pendulum, a gas services company with experience in daily nominations, contract administration, and asset management, to be responsible for the daily workings of all of the gas supply and transportation contracts for the proposed facility. Therefore, BPD should have the ability to monitor the different contracts to ensure that the potentially numerous gas transactions are carried out in a reliable, timely and least cost manner.

It is likely that fuel supplies selected by individual customers will be low cost due to the ability to take advantage of a variety of gas suppliers and transportation options. However, the Siting Board finds that a firm transportation contract from a major interconnection point to the proposed project site is essential to ensuring that BPD's gas supply strategy is viable. Therefore, the Siting Board requires that BPD provide the Siting Board with signed contract(s) for 335 days or more of firm transportation from Wright (or a comparable location) to the proposed facility, or a comparable arrangement, such as firm deliverability based on transportation from Wright combined with downstream supplies.

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 asserts that gas will be available for all but between 64 and 100 hours in most years. We recognize that past experience relating to supply of pipeline gas to New England may provide a reasonable basis for the Company's assumption regarding the ability to receive gas in quantities above those contracted for on a firm basis. Here, however, BPD's gas supply strategy includes the potential for a varied mix of contracts with differing terms and conditions. Although Pendulum is highly qualified to monitor the gas supply portfolio for BPD, it is unclear that BPD's proposed gas contract for 335 days of firm transportation from Wright would provide adequate assurance that BPD's expectations regarding minimum use of oil firing in most years would be met. The Siting Board further addresses this issue in Sections III.B.2.a. and III.B.4.a, below.

Accordingly, the Siting Board finds that based on compliance with the above condition that BPD provide the Siting Board with a signed firm transportation contract for 335 days or more from Wright (or a comparable location), or a comparable arrangement, BPD 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 BPD has established that (1) upon compliance with the condition relative to providing a copy of 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 providing a copy of a signed contract(s) for 335 days or more of firm transportation from Wright (or a comparable location), or a comparable arrangement, 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, upon compliance with the aforementioned conditions, BPD will have 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. and II.C.3., above, BPD will have established that (1) its 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, BPD 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. 1993 BECo Decision 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. New England Power Company, EFSB 94-1, at 50 (1995) ("1995 NEPCo Decision"); Cabot Decision, 2 DOMSB at 373; 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 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. 1995 NEPCo Decision, EFSB 94-1, at 54-55; Cabot Decision, 2 DOMSB at 373; Berkshire Gas Company (Phase II), 20 DOMSC at 109 (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.[121]

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[121] When a facility proposal is submitted to the Siting Board, the petitioner is 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

1995 NEPCo Decision, EFSB 94-1 at 57-59; Altresco Lynn Decision, 2 DOMSB at 144-145; NEA Decision, 16 DOMSC at 381-409. In past decisions, the Siting Board has not required a noticed alternative site in cases involving proposals to construct cogeneration facilities if the cogeneration proponent (1) had a steam sales agreement with existing steam purchaser(s) sufficient to qualify it for QF status, and (2) had a proposed site fully within the property boundaries of the principal steam host. Cabot Power Decision, 2 DOMSB at 373-374; Altresco Lynn Decision, 2 DOMSB at 165; MASSPOWER Decision, 20 DOMSC at 328.[122]

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

2. Development of Siting Criteria

BPD stated that it developed and administered an innovative Site Selection RFP ("SS-RFP") to select a site (Exh. BP-1A at 6-6). BPD stated that its site selection process differs from that of projects previously reviewed by the Siting Board since this is the first time that an RFP has been used to select a site (Company Brief at 70). BPD stated that the SS-RFP was designed to (1) provide comprehensive project information to potential community bidders, and (2) elicit the data necessary to enable BPD to review identified sites in a systematic and consistent manner, based on comprehensive cost, environmental, and other criteria (Exh. BP-

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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.

[122] 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. However, the proposed site is not located in the coastal zone, and is not subject to these regulations.

1A at 6-8, 6-9). The Company asserted that its RFP-based site selection process was designed to meet the Siting Board's site selection objectives, in order to ensure the construction of a least-cost, least-environmental impact, reliable facility at a site with demonstrable community support (id. at 6-4; Company Brief at 70).

a. Description

The Company stated 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 evaluative site criteria (Exh. BP-1A at 6-10, 6-15). The Company reported that it developed its criteria and scoring system[123] before it received specific site proposals for consideration from communities (Tr. 4, at 21). BPD stated that its threshold criteria included: (1) location in a municipality with a Tennessee mainline or lateral; (2) location in a municipality with a transmission line of 115 kV or greater; (3) a minimum site size of eight acres with a minimum of seven acres of buildable land; (4) a minimum water supply of 1.5 mgpd available starting in 1999; (5) the ability to discharge up to 245,000 gpd of treated wastewater to a local wastewater treatment plant beginning in 1999; (6) suitable soil to accommodate development of heavy industry; (7) no apparent archaeological or historically significant structures; and (8) no apparent threatened or endangered species or habitat (Exh. BP-1A at 6-10, 6-11).

The Company stated that it also developed major evaluative site criteria, broken down into 13 categories and 31 total subcategories, where each of the 31 subcategories were to be individually scored (id. at 6-15, 6-16). BPD explained that the criteria were focused on achieving the objectives of environmental suitability, development compatibility, ease of construction and minimum cost (id. at 6-13). The Company stated that it developed criteria in

[123] The Company's witness stated BPD had used a screening system based on the evaluation of site attributes, followed by a final selection process based on evaluating the facility impacts at respective sites (Tr. 4, at 46). The Company's witness testified that he had used a variation of this type of system in siting a number of industrial facilities (id. at 17).

the following categories to rank the offered sites: (1) earth resources: site base elevation, topography, potential for subsidence or erosion, depth to bedrock, potential for site contamination, and existence of prime agricultural soils at the site; (2) air resources: dispersion environment and interacting sources; (3) water resources: surface water resources, groundwater resources, and floodplain proximity; (4) terrestrial ecology: endangered species/significant habitat; (5) aquatic ecology: mapped wetlands/waterbodies, and significant habitat; (6) land use/zoning: land use compatibility, site zoning designation, proximity to residences and sensitive receptors, and site size and buffering potential; (7) transportation: adequacy of roadway/rail infrastructure, and constraints to roadway capacity; (8) noise: potential for compliance with local or state noise regulations, and distance to sensitive receptors and buffering potential;[124] (9) utilities: electrical interconnection,[125] gas interconnection, water/sewer interconnection, and water supply permit status; (10) community support: level of community support,[126] and willingness of municipality to execute tax agreement; (11) socioeconomics: compatibility with community development objectives; (12) visual resources: project visibility and compatibility with viewshed, and site buffering/mitigation potential; and

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124 This criteria encompassed both the distance from the property line of the potential site to the nearest sensitive receptor or residentially zoned area, and the distance from the footprint of the proposed project to the nearest sensitive receptor (Exh. BP-1A at 6-28). The Company indicated that sensitive receptors are places of worship, hospitals, nursing homes, and schools (id. at 6-24).

125 A site received: (1) a high ranking for electric interconnection if an existing 115 kV line was located within one mile of the site boundary, interconnection would not involve significant upgrades, and all upgrades would be within the host community; (2) a medium ranking if interconnection would require moderate upgrades, but the site otherwise would receive a high ranking; and (3) a low ranking if the nearest existing transmission line was located more than one mile from the site, or if interconnection would require either significant upgrades or upgrades in more than one community (Exh. BP-1A at 6-29).

126 The Company stated that site suitability ratings for the level of community support criteria were based on support by elected officials, response to the SS-RFP, media response, and the community's historical response to heavy industrial development Exh. BP-1A at 6-31)

(13) cultural resources: degree of historical or archaeological significance (id. at 6-16 to 6-34).

The Company ranked each criterion as either very important, of moderate importance, or of minor importance (id. at 6-14, 6-35).[127] The Company then evaluated each potential site by assigning suitability ratings of high (3 points), medium (1 point) or low (0 points) for each criterion (id.).[128] Finally, the Company developed an overall suitability score for each site by developing a weighted average of individual suitability scores, such that each very important criterion contributed five percent of the overall score, each moderate criterion contributed 2.5 percent, and each minor criterion contributed 0.5 percent (id. at 6-35, 6-36; Tr. 4, at 14, 15).

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. Enron Decision, 23 DOMSC at 127. Here, BPD 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 the site selection criteria which the Siting Board has found to be appropriate in previous reviews. Cabot Decision, 2 DOMSB at 380-381; Altresco Lynn Decision, 2 DOMSB at 169; MASSPOWER Decision, 20 DOMSC at 378-379.

The Siting Board has concerns regarding three of the specific criteria used to rank sites. First, the Siting Board notes that one of the Company's criteria for noise impacts takes into account the distance to residentially zoned areas but not to individual residences. Thus, the noise ratings may not reflect the proximity of residences that are not located in residentially

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127 Of the 31 evaluative criteria, 13 were determined to be very important, 13 were determined to be of moderate importance, and 5 were determined to be of minor importance (Exh. BP-1A at 6-35, 6-36).

128 The Company stated that it chose a 3:1 weighting in order to reward sites with very positive attributes (Tr. 4, at 13, 44).

zoned areas, but nonetheless would be designated as residential receptors for purposes of noise analyses.

Second, the Siting Board notes that, while the Company's criteria for evaluation of the level of community support includes important factors such as the support of elected officials and media support, these factors alone may not present a complete picture of community support. The Siting Board recognizes that no large industrial project will receive unanimous local community support. However, a site that is selected with significant input from local citizenry is less likely to encounter grassroots opposition, and such input has not been fully captured in the stated criteria.

Third, the Siting Board notes that BPD's electrical interconnection criteria do not adequately reflect the cost and environmental issues associated with a electric interconnect of a significant distance, such as the 4.5-mile interconnect at the alternative site. These criteria fail to distinguish between relatively short (just over a mile) and relatively long interconnections, except when the longer interconnection crosses into another community. In the future, BPD and other petitioners should assess electric interconnection impacts in a manner that more fully considers the length of the interconnect.

After developing a set of evaluative criteria, BPD assigned varying weights to the these criteria based on the level of importance of each criterion in the selection of a suitable site. The Company then developed a scoring mechanism by detailing specific indicators that define the ranking of a site for each criterion. The Company thus incorporated a systematic qualitative approach to comprehensively evaluating site attributes based on their relative importance for ensuring a least-cost, minimum-environmental-impact project.

Overall, by following a comprehensive weighting and scoring system, BPD has addressed the Siting Board concerns raised in previous decisions regarding the need for quantifying weights and scores as part of a site selection criteria. 1993 BECo Decision, 1 DOMSB at 57-58; Enron Decision, 23 DOMSC at 127; MASSPOWER Decision, 20 DOMSC at 378-379.

Accordingly, the Siting Board finds that BPD has developed a reasonable set of criteria for identifying and evaluating alternative sites.

3. Application of Siting Criteria

a. Description

BPD indicated that prior to the issuance of the SS-RFP, it determined that it was necessary to locate the proposed facility in western Massachusetts (Exh. BP-1A at 6-5; Tr. 4 at 64).[129] The Company explained that it then selected 23 communities in western Massachusetts in which either a Tennessee mainline or major lateral was located, and sent information describing the proposed project to these communities with instructions to return an "expression of interest" letter if they wished to be considered as a host site for the proposed project (Exh. BP-1A at 6-5, 6-8). BPD stated that it received twelve letters of interest requesting copies of the SS-RFP, and that eleven communities responded to the SS-RFP, offering one or more sites, for a total of 20 sites (id. at 6-8, 6-12).[130]

The Company asserted that its use of a SS-RFP helped address the potential problem of lack of community support which can contribute to delays, increase permitting costs, or even end a project (Exh. HO-S-4). The Company reported that Agawam and Southwick demonstrated verified community support through endorsement letters from elected and appointed officials, and that Agawam also provided endorsements from its Chamber of

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129 The Company stated that in the earliest stages of project development, the Company selected southern New England as a potential location for its project and then focused on western Massachusetts (Exh. BP-1A at 6-4). BPD identified three reasons for selecting western Massachusetts: (1) the ability to locate in close proximity to a natural gas pipeline without capacity constraints; (2) the ability to locate in close proximity to major electric transmission facilities; and (3) the ability to minimize wheeling charges by interconnecting with a utility that does business with many other utilities (id. at 6-6).

130 The following communities responded to the SS-RFP: Adams, Agawam (5 sites offered), Chesire, Easthampton, Holyoke, Lanesborough, Lee, North Adams, Pittsfield (2 sites offered), Southwick (5 sites offered), and Westfield (Exh. BP-1A at 6-12).

Commerce (Tr. 4, at 18).[131]

Based on the responses to the RFP, the Company determined that all of the proposed sites met the threshold criteria described in Section III.A.2.a., above (id. at 8). A team led by Earth Tech and consisting of members of BPD, B&V, and ABB conducted site reconnaissance surveys[132] of between one and two hours to assess potential engineering constraints, environmental features, and interconnection alternatives at each of the sites (Exhs. HO-S-13; BP-1A at 6-15). The Company then applied the 31 evaluative criteria to develop weighted scores for each site, and developed a short list of sites based on the site suitability rankings (Exh. BP-1A at 6-15).

The Company indicated that it selected a short list of five sites, and conducted more extensive site visits to the top three sites, designated Agawam 4/5, Agawam 1/2,[133] and Westfield (Exhs. HO-S-13; HO-S-20). BPD then conducted an in-depth engineering review of the short-listed sites to determine the environmental impacts, costs and engineering issues

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131 The Company reported that it met with elected officials, community leaders and business leaders in Southwick on November 10, 1994 and in Agawam on January 12, 1995 (Exh. HO-S-16). BPD stated that it met with the Southwick officials prior to the Town of Southwick's response to the SS-RFP to present information concerning the proposed project (Tr. 4, at 24, 25). BPD also met with residents of Losito Lane, in Agawam, at the residents' request on January 11, 1995 (id. at 26; Exh. HO-S-16). The Company held a public hearing in Agawam on March 15, 1995 to answer questions and receive comments (Exh. HO-S-16; Tr. 4, at 27, 28).

132 The Company stated that, prior to the site reconnaissance visits, each site was located on geographic information system maps and nearby roadways, airports, waterways, electric transmission lines, the Tennessee mainline, major gas laterals, groundwater wells, surface water reservoirs, designated open space areas, state-designated Areas of Critical Environmental Concern, state Natural Heritage Endangered Species Program priority habitat areas, MDEP approved and interim Zone II protection areas, MDEP permitted solid waste facilities, and areas of complex terrain were identified (Exh. HO-S-13).

133 In response to the SS-RFP, Agawam submitted five sites (Exh. BP-1A at 6-12). The Company stated that it combined adjacent parcels where the combination would result in a higher suitability score (id. at 6-36). Agawam sites 1 and 2 were combined to form one site, Agawam 1/2, and Agawam sites 4 and 5 were combined to form a second site, Agawam 4/5 (id.).

associated with developing the proposed facility at each site (Tr. 4, at 45). Based on these site visits and the engineering review, BPD selected Agawam 4/5 as its primary site and Westfield as its alternative site (Exh. BP-1A at 6-38).[134] After being notified in May, 1995 that the Westfield site was no longer available, the Company conducted an extensive site visit at a fourth short-listed site, known as Southwick 1,[135] and selected the Southwick 1 site as its new alternative site (Exh. HO-S-20).

b. Analysis

The Siting Board previously has stated that the site selection process for an IPP generally should involve the consideration of a broader range of alternatives than other proposed energy projects since an IPP is not constrained by the necessity to locate in a specific area. Enron Decision, 23 DOMSC at 129. Here, the Company issued an SS-RFP soliciting prospective sites from a targeted group of communities, with an approximately 50 percent response rate. The record indicates that all 23 sites offered in response to the SS-RFP met the threshold criteria established by the Company. The Company applied its evaluative criteria in a comprehensive manner, and scored the sites methodically. BPD then utilized both the weighted score rankings and a follow-up facility impact analysis based on in-depth site visits to determine that the primary site was superior to the other sites.

In the past, the Siting Board 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. Altresco Lynn Decision, 2 DOMSB at 173. Here, BPD has attempted to incorporate

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[134] The Company noted that Agawam 4/5 and Agawam 1/2 were 2,000 feet apart, and would not provide sufficient geographic diversity if chosen as the primary and alternative sites (Exhs. BP-1A at 6-37; HO-S-6). Therefore, the Company stated that it selected the optimal Agawam site for its primary noticed site (Exh. BP-1A at 6-37, 6-38).

[135] The Company indicated that the other remaining short-listed site, known as Agawam 3, had been withdrawn in December 1994 since it was unavailable for purchase or lease (Exh. BP-1A at 6-37).

local input through its SS-RFP, through meetings with local leaders and residents, and through a public hearing. It is clear that an SS-RFP can be a valuable tool for siting power plants, and that BPD's use of the SS-RFP and its initial discussions with business and community leaders represent a significant attempt to assess local support for its project. However, the SS-RFP necessarily assesses local government support for a project, rather than the support of the community as a whole. The Siting Board stresses that such support is only one component of community acceptance. The Siting Board therefore recommends that, in future site selection processes, project proponents develop better methods for assessing grassroots support for a project site, perhaps through public informational meetings early in the selection process. If possible, this assessment should be included in the evaluative site criteria.

Nonetheless, based on the foregoing, the Siting Board finds that BPD 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.

4. Geographic Diversity

In this section, the Siting Board considers whether BPD's site selection process included consideration of site alternatives with some measure of geographic diversity. BPD asserted that it has identified at least two noticed sites with some measure of geographic diversity (Exh. BP-1A at 6-40). The Company explained that, early in the site selection process, it noticed that the two sites ranked first and second were located 2,000 feet apart in Agawam, and determined that designating these sites as the primary and alternative sites would not meet the Siting Board's geographic diversity standard (id. at 6-37; Exh. HO-S-6). The Company then compared the two Agawam sites in order to select the better Agawam site for its primary noticed site and selected a site in another town, namely Southwick, for its alternative site (Exh. BP-1A at 6-37, 6-38). The primary site and alternative sites are located in adjacent towns, approximately three miles apart (Exh. S-22, att.).

The Siting Board requires that an applicant must provide at least one noticed alternative with some measure of geographic diversity. 1995 NEPCo Decision, EFSB 94-1 at 50, 59;

1993 BECo Decision, 1 DOMSB at 64; 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. 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, BPD has provided two sites located three miles apart in neighboring towns with significantly different environmental characteristics, such as site size and natural resource conditions.

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

5. Conclusions on Site Selection Process

The Siting Board has found that: (1) BPD has developed a reasonable set of criteria for identifying and evaluating alternative sites; (2) BPD 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) BPD has identified at least two practical sites with a sufficient measure of geographic diversity.

Accordingly, the Siting Board finds that BPD 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. 1993 BECo Decision, 1 DOMSB at 37-38; 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. Cabot Decision, 2 DOMSB at 389; Altresco Lynn Decision, 2 DOMSB at 177; EEC Decision, 22 DOMSC at 334, 336. A facility proposal which achieves that appropriate balance is one that meets the Siting Board's statutory requirement to minimize environmental impacts. Cabot Decision, 2 DOMSB at 389; Altresco Lynn Decision, 2 DOMSB at 177; 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. Cabot Decision, 2 DOMSB at 389; Altresco Lynn Decision, 2 DOMSB at 177; 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. Cabot Decision, 2 DOMSB at 389; Altresco Lynn Decision, 2 DOMSB at 177; 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. Cabot Decision, 2 DOMSB at 389; Altresco Lynn Decision, 2 DOMSB at 177; 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, 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.[136] Cabot Decision, 2 DOMSB at 389-390, 421-422; Altresco Lynn Decision, 2 DOMSB at 177, 214; 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. Cabot Decision, 2 DOMSB at 390; Altresco Lynn Decision, 2 DOMSB at 178; 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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136 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");[137] Prevention of Significant Deterioration ("PSD") requirements; New Source Review ("NSR") requirements; and New Source Performance Standards ("NSPS") for criteria pollutants (Exh. BP-1B at 7-4). The Company further indicated that the proposed facility will fall under Title IV Sulfur Dioxide Allowances and Monitoring regulations beginning in the year 2000 (Exh. HO-E-26(att.) at 3-2).

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"). The Company further indicated that, although the Agawam 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.[138] 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, CO and PM-10, pollutants for which emissions may potentially exceed 100 tpy. The Company indicated that under NSR requirements, the proposed facility must apply LAER technology and emissions offsets to any directly emitted pollutant which is a precursor to O_3, and which the proposed facility may emit at levels greater than 50 tpy. Thus, the Company must apply LAER technology to control NOx. 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 threshold levels.

The Company noted that the proposed facility would also incorporate BACT for SO_2,

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137 The MDEP has adopted the NAAQS limits as MAAQS.

138 The Company indicated that O_3 is a regional pollutant resulting from NOx and VOC emissions (Exh. BP-1A at 7-19).

Pb and VOCs, pollutants regulated as part of the MDEP air plans approval process.

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 (Exhs. BP-FS-2, at 3-10, 3-27 to 3-30; HO-E-26(att.)). The Company asserted, however, that air quality impacts from the proposed facility would be minimized through the use of efficient technology, clean fuels, BACT, acquisition of offsets and facility dispatch (See Section II.A.4, above) (Exh. BP-1B at 7-48; HO-E-26(att.) at 4-1 to 4-14).

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. HO-E-26(att.) at 4-1 to 4-14; BP-FS-2, at 3-16). The Company provided calculations of air emissions for the proposed facility for two scenarios, one which assumes natural gas firing for 365 days per year at 100 percent load, and a second which assumes 720 hours' firing of low-sulfur distillate oil and natural gas firing for the remainder of the year, all at 100 percent load (Exhs. BP-1B at 7-22; BP-FS-2, at 3-16, Table 3.1-5; Tr. 3, at 16-17). The Company stated that it did not anticipate that the proposed facility would use oil for more than 100 hours per year in most years (Exh. HO-E-26(att.) at 4-1 to 4-2). The Company asserted, however, that the proposed project was likely to operate as a merchant power plant and therefore required the ability to use oil for up to 720 hours per year (id.).[139]

The Company maintained that the proposed facility as designed would incorporate BACT for CO, PM-10, SO_2, Pb and VOCs, and LAER for NOx (Exh. BP-1B at 7-10 to 7-11). The Company asserted that emission rates for non-criteria pollutants and sulfuric acid

139 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 produce power at the lowest possible cost (Exh. HO-E-26(att.) at 4-1 to 4-2; Tr. 3, at 95-96). See Section II.C.3.b, above.

would also represent BACT (Exh. HO-E-26(att.) at 4-11). The Company provided supporting information regarding control options for criteria and non-criteria pollutants, including a discussion of trade-offs between control of CO and PM-10, and control of NOx, VOCs and CO, to back its contention that assumed facility emission rates would represent BACT and/or LAER for the identified pollutants (id. at 4-1 to 4-13, Table 4-2; Tr. 3, at 8-11, 14-17, 32-37, 82-83, 86-94, 97-101, 107-108, 112-115; Tr. 9, at 1-16).

The Company asserted that predicted air pollutant concentrations resulting from emissions from the proposed facility would be "insignificant" relative to ambient air quality standards (Exh. BP-1B at 7-27). In support of its assertion, the Company provided local air quality modeling results[140] indicating that impacts of the proposed facility on ambient concentrations of criteria pollutants would be below SILs, assuming a stack height of either 167.5 feet,[141] or 125 feet (Exh. HO-E-26(att.) at 5-9 to 5-24).[142]

The Company also provided predicted ambient concentrations of air toxics from the

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140 The Company indicated that it relied principally on the Industrial Source Complex Short Term ("ISCST2") and the COMPLEX1 models to calculate emissions at various locations and heights relative to the stack and plume of the proposed facility (Exhs. BP-1B at 7-27; HO-E-26(att.) at 5-1). The Company stated that when ISCST2 screening level modeling of emissions from the proposed facility yielded concentrations above significant impact levels ("SIL"), the Company conducted refined analyses (Exh. HO-E-26 at 5-10). The Company also indicated that for complex terrain, i.e., terrain above stable plume height (as differentiated from "simple" terrain which is below stack height and "intermediate" terrain which is above stack height and below stable plume height), CTSCREEN modeling was performed for those pollutants for which COMPLEX1 modeling produced concentrations above significant impact levels (id. at 5-20; Exh. BP-1B at 7-27).

141 For the proposed facility, a stack based on Good Engineering Practice ("GEP") guidelines would be 167.5 feet high (Exh. HO-E-26(att) at 5-8). Use of GEP stack height minimizes building downwash effects (id.).

142 The Company's analysis indicates that ambient concentrations of criteria pollutants emitted from the proposed facility when gas-fired, measured in micrograms per cubic meter and expressed as a percentage of SILs, would range from less than one percent to as much as 13 percent assuming a 167.5-foot stack, and from less than one percent to as much as 48 percent assuming a 125-foot stack (Exh. BP-FS-2, at 3-28).

proposed facility with a 167.5 foot stack and with a 125-foot stack (Exhs. HO-E-26(att.) at 5-25; HO-RR-9(att.)). The Company indicated that the concentrations were derived by scaling from the refined level ISCST2 and CTSCREEN model results for SO_2 (id.).[143] Based on its analysis, the Company stated that concentrations of air toxics from the proposed facility with a 125-foot stack would be below applicable standards[144] for all cases except the 24-hour average predicted concentration for formaldehyde (Exhs. HO-E-26(att.) at 5-25; HO-RR-9(att.); Tr. 3, at 12 to 14). The Company stated that if the 125-foot stack height were approved by MDEP, the Company would meet an emission limit of 0.00193 lb/MMBtu for formaldehyde to ensure the proposed project's compliance with the TEL for formaldehyde (Exh. HO-RR-9(att.) at Table 5-16).

The Company asserted, citing supporting documentation, that ambient concentrations from its proposed facility, notably predicted annual contributions of SO_2, would have no negative impacts on sensitive vegetation and soils (Exh. BP-FS-2, at 3-36 to 3-37). The Company further asserted that the maximum predicted contributions of SO_2 from the proposed facility, even assuming a 125-foot stack and distillate oil firing, would be insignificant relative to existing ambient concentrations (id.; Tr. 9, at 23 to 24).

(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. HO-E-26(att.) at 4-13). 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

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143 Scaling was performed by dividing the SO_2 concentration by the SO_2 emission rate and then multiplying by the emission rate for each air toxic (Exh. HO-E-26(att.) at 5-25).

144 Applicable standards are MDEP Threshold Effects Exposure Limits ("TELs") and annual average Allowable Ambient Limits (Exh. HO-E-26(att.) at 5-25).

of 109 tons per year, the proposed facility will require 137 tons of NOx ERCs per year (id. at 4-2, 4-13). The Company asserted that the most viable sources of offsets for the proposed project would be from future shutdown or curtailment of existing electric generating plants (Exh. HO-E-1(att.) at 2-2 to 2-3). The Company indicated that, because the market in Massachusetts for NOx ERCs was in its infancy, the Company's primary plan was to acquire the necessary ERCs through its power sales process (id.).[145]

The Company indicated that the proposed project would emit 796,430 tpy of CO_2[146] and asserted that the CO_2 impacts of the proposed facility would be minimized consistent with Siting Board requirements (Exhs. HO-RR-10, at rev. att. 4-5; BP-FS-2, at 3-29 to 3-30). The Company argued that several factors would contribute to the minimization of CO_2 impacts from the proposed facility: the proposed facility's low heat rate; the Company's plan to distribute a significant number of trees annually, coupled with negligible tree-clearing required for construction of the proposed facility; and the displacement, as a result of the operation and dispatch of the proposed facility, of between 1.6 million and 4.4 million tons of CO_2 over the facility's 20-year life (Tr. 9, at 97-98; Company Brief at 79-80). The Company also asserted that its proposed purchase of NOx offsets from a source shutdown or curtailment would result in collateral CO_2 offsets (Exh. BP-1B at 7-35).[147]

The Company provided information regarding a program it had begun in 1995 to

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145 The Company stated that, because offsets might not be available through its power sales process, the Company was pursuing acquisition of offsets from other sources (Exh. HO-E-1(att.) at 2-2 to 2-3).

146 The Company indicated that this emission rate is based on 64 hours per year of oil burning (Exh. BP-1A at 4-18). Assuming the maximum oil-fired generation of 720 hours, the Company indicated the proposed facility would emit 826,418 tpy of CO_2 (Exh. HO-RR-10).

147 The Company stated that if NOx offsets were obtained in any fashion that would not generate collateral CO_2 emission reductions, the Company would likely rely on a more traditional tree-planting approach, such as the one required in past Siting Board decisions, or on implementation of its seedling distribution program to offset CO_2 emissions (Exhs. HO-E-26 (att.); HO-RR-59; Tr. 9, at 97-105).

distribute approximately 4,000 seedlings each year on Earth Day, consistent with commitments by BPD to Town officials (Exh. HO-RR-59; Tr. 9, at 97-105, 102). The Company stated its willingness to continue this program for the life of the project and indicated that it considered its seedling distribution program to be part of its strategy to offset CO_2 emissions associated with the proposed facility (id. at 97-98).

The Company indicated that curtailment or shutdown of oil-fired capacity sufficient to provide BPD's required NOx offsets would provide CO_2 offsets amounting to 91,700 tpy, or 11.5 percent of BPD's annual CO_2 emissions (Exh. BP-1B at 7-35).[148] However, due to uncertainties regarding the availability of CO_2 offsets, BPD committed itself to providing curtailment/shutdown offsets amounting to only one percent of BPD's CO_2 emissions, or to doubling its seedling distribution program to 8,000 seedlings per year in lieu of such offsets (Tr. 13, at 62-63; Company Brief at 81).

The Company stated that CO_2 offsets are not required under any regulatory program other than the Siting Board review (Tr. 9, at 132-133). BPD noted that the United States has established a goal of holding or reducing annual CO_2 emissions to 1990 levels by the year 2000, consistent with an agreement among the United States and other nations at the 1992 Earth Summit in Rio de Janeiro (Tr. 9, at 65, 97). BPD provided the U.S. report Emissions of Greenhouse Gases in the United States, 1987-1994, which indicates that CO_2 emissions in the United States increased from 4.82 billion metric tons ("bmt") in 1987 to 5.04 bmt in 1990 to 5.24 bmt in 1994 (Exh. HO-RR-58(att.) Table ES1).[149]

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148 Collateral CO_2 offsets would be at a smaller but comparable level for the shutdown or curtailment of a gas-fired or coal-fired source (Exh. HO-RR-55).

149 The Company's dispatch analysis indicates that, for a range of load forecasts and assumed supply sources, without the BPD project, CO_2 emissions from electric utility sources in New England would total 39.8 to 43.9 million tons in 1999, increasing to a total of 66.8 to 100.4 million tons in 2018 (Exhs. BP-1A at att. 3-32; HO-RR-44(red.)). With inclusion of the BPD project as a supply source, the corresponding amounts of CO_2 emissions would total 38.8 to 43.7 million tons in 1999, increasing to a total of 67.0 to 100.3 million tons in 2018 (Exhs. BP-1A at att. 3-32; HO-RR-44(red.)). See Section II.A.5, above.

The Company indicated that the United States Department of Energy administers the Climate Challenge Program, a voluntary program for the registration of electric utility industry efforts to control emissions of greenhouse gases, such as CO_2 (Exh. HO-RR-56). BPD asserted that its proposed CO_2 offset measures are consistent with the intent of the Climate Challenge Program, although to date BPD has not pursued participation in the program (id.).

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 (Exh. BP-1B at 8-3). The Company provided modeling results indicating that air quality impacts from operation of the proposed facility at the Southwick site would be greater than those at the Agawam site (id.). Based on its analysis, the Company asserted that the Agawam site would be preferable to the Southwick site with regard to air quality impacts (id. at 8-6). In its comparison, the Company assumed construction of the proposed facility with a 167.5-foot stack at both the Agawam and Southwick sites. The Company explained that the higher predicted air quality impacts at the alternative site reflect the relatively higher land elevations in proximity to that site (id. at 8-5).

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. However, the Company has provided separate estimates of emissions assuming 365 days of gas firing and assuming dual fuel firing including 720 hours of oil firing. In addition, the Company has provided separate analyses of air quality impacts for the proposed facility with a 125-foot stack and a 167.5-foot stack which indicate that air quality impacts of the proposed facility at both sites would be lower with a 167.5-foot GEP stack.

The Siting Board notes that BPD proposes to use a 125-foot stack at the primary site in order to reduce visual impacts at that location (See Section III.B.2.c, below). However, the record indicates that local ambient air quality impacts would be marginally higher with a lower stack. Thus, the Company has not selected a facility design which results in the lowest ambient air quality impacts.

In addition, the Siting Board notes that in the three most recent gas-fired facility cases, each project developer had contracted for gas on a firm basis for 365 days per year. Cabot Decision, 2 DOMSB at 366; Altresco Lynn Decision, 2 DOMSB at 146; Enron Decision, 23 DOMSC at 108.[150] Here, BPD expects to rely on limited periods of oil-fired generation -- specifically, periods of such generation that BPD expects would amount to 100 hours or less in most years. Further, BPD maintains that it needs to retain the ability to operate on oil for a maximum of 720 hours per year, in the event gas deliveries are curtailed for such periods under possible terms of gas supply and transportation contracts. Finally, as discussed in Section II.C.3.b, above, BPD indicates that it likely would rely on more than one gas contract to supply the proposed facility, with potentially different terms and conditions. Thus, the record in this case does not present the same assurances as provided in recent reviews of generating facilities that oil-fired operations would be substantially minimized.

Accordingly, based on its review of the Company's analysis of emissions and local air quality modeling, the Siting Board finds that the Company has not established that air quality impacts of the proposed facility at the primary site would be minimized. The Siting Board will review the balance between air quality impacts, visual impacts, and cost in Section III.B.4,

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[150] The Siting Board notes that the Altresco Lynn facility was permitted for only five days of oil firing per year, and the Enron facility's back-up plans did not include oil-firing. Altresco Lynn Decision, 2 DOMSB at 149; Enron Decision, 23 DOMSC at 113-114. The Cabot facility was permitted for 30 days of oil firing although use of its permitted low sulfur fuel oil for the maximum of 30 days was allowed only in the event of emergency situations, when both liquified natural gas and natural gas were not available. Cabot Decision, 2 DOMSB at 366. The Siting Board specifically addressed the issue of its expectation that fuel oil substitution for economic reasons would not occur. Id.

below.

With respect to air quality impacts at the alternative site, the Siting Board notes that even with a GEP stack of 167.5 feet at Southwick and a 125-foot stack at Agawam, air quality impacts from the proposed facility are predicted to be slightly higher at the Southwick site, reflecting differences in topography at the two locations. The Siting Board therefore finds that the primary site would be slightly preferable 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 O_3 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.

The Siting Board first established in the Enron Decision the requirement that all proponents of proposed facilities that emit CO_2 must comprehensively address the mitigation of CO_2 impacts. 23 DOMSC at 196. In its Eastern Energy Corporation Final Decision on Compliance with Environmental Conditions, 25 DOMSC 296, 358-360 (1992) ("EEC Compliance Decision"), the Siting Board required future applicants to present a comprehensive analysis of alternative CO_2 mitigation plans, including likely arrangements for ensuring implementation and verification of estimated results, in order to demonstrate that all cost-effective approaches have been considered. 25 DOMSC at 358-360. Further, the Siting Board set forth the general criteria it would consider in determining the adequacy of CO_2 mitigation, including the relationship of that mitigation to factors such as facility cost, facility CO_2 emissions, and any increment of such emissions exceeding the emissions of displaced capacity. Id., 25 DOMSC at 361-365. Finally, the Siting Board stated that, in determining the appropriate CO_2 mitigation level based on the above criteria in a particular case, it would consider the balance between the interest of CO_2 mitigation and other interests, including cost, viability, other environmental mitigation and any facility benefits such as supply diversity. Id., 25 DOMSC at 365.

In the EEC Compliance Decision, the Siting Board required the petitioner to commit $2 million for CO_2 mitigation, with an unspecified allocation between an in-state shade tree planting program and a more cost-effective identified approach of participation in a local, national or international reforestation program. Id. at 365-367. In two later generating facility reviews for which initial petitions had been filed prior to the establishment of the general standard in the EEC Compliance Decision, the Siting Board held that a CO_2 commitment comparable to that required in the EEC Compliance Decision was appropriate, but determined comparability based on the tons of emissions to be offset as a percentage of total emissions, rather than based on cost.[151] See Cabot Decision, 2 DOMSB at 397; Altresco Lynn Decision, 2 DOMSB at 183-184.

We note that the levels of CO_2 offsets in past reviews, although accepted as the appropriate balance between environmental impact and cost based on the record in such reviews, represent the mitigation of less than one percent of facility emissions. The record in this review establishes that the United States has set and continues to pursue a goal of holding or reducing emissions to 1990 levels. The record further establishes that CO_2 emissions have increased nationally in recent years, and that such emissions from electric utility sources in New England are projected to increase significantly over the life of the proposed facility.

A number of years have passed since the Siting Board set forth its above-mentioned general standard for CO_2 mitigation. There may now be opportunities to provide CO_2

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151 To determine the commitment that was comparable to that in the EEC Compliance Decision, for purposes of these later reviews, the Siting Board assumed that 0.8 percent of total facility emissions would be offset by the required cost commitment in the EEC Compliance Decision. Altresco Lynn Decision, 2 DOMSB at 186, 219. However, because facility construction in the EEC Compliance Review was to involve significant on-site tree clearing -- an impact that would negate approximately 56 percent of the required CO_2 offsets -- the Siting Board concluded that applicants in such later reviews could meet the comparability requirement based on attaining a net CO_2 offset level, after adjusting for any on-site tree clearing. Id. at 219. Thus, given a facility that was to require no on-site tree clearing, the Siting Board determined the comparable CO_2 offset commitment to be 0.348 percent of total facility emissions. Id.

mitigation that would be significantly more cost-effective than that accepted in past Siting Board reviews, and at the same time, provide a higher level of CO_2 offsets that better establishes that CO_2 impacts would be minimized. The Siting Board now has before it the first generating facility petition filed after the establishment of the general standard for CO_2 mitigation in the EEC Compliance Decision. BPD has identified two forms of environmental mitigation to offset CO_2 emissions: (1) contracted shutdown or curtailment of existing CO_2 sources through direct or collateral purchase (with the purchase of NOx ERCs) of CO_2 offsets, and (2) implementation of a seedling distribution program. In addition, based on its 20-year dispatch analysis, BPD asserted that its project would displace generation that otherwise would emit 10-28 percent more CO_2 than the proposed facility over that period.

In setting forth its CO_2 mitigation plan, the Company initially proposed both (1) to acquire offsets that would be collateral to NOx ERCs, amounting to up to 11.5 percent of facility CO_2 emissions, (conservatively estimated at a cost of up to \$411,000 to \$685,000), and (2) to distribute 4,000 seedlings per year for 25 years (at a total cost of \$250,000 to \$375,000). However, BPD has since modified its proposed mitigation to either (1) obtaining offsets of one percent of BPD CO_2 emissions from shutdown or curtailment of existing generation facilities plus distribution of 4,000 seedlings per year; or (2) distribution of 8,000 seedlings per year.

The Siting Board notes that BPD's seedling distribution program would provide a level of CO_2 offsets that is generally comparable, on a cumulative long-term basis, to the offset levels associated with tree planting arrangements accepted by the Siting Board in the past. Specifically, BPD would provide either 100,000 or 200,000 seedlings over 25 years, representing annual offsets that would amount, by the twentieth year of facility operation, to either 0.275 or 0.550 percent of total facility emissions. The Siting Board notes that an annual offset level of 0.550 percent of facility emissions, the higher offset level identified by BPD, would be a clear increase above the net annual offsets required by the Siting Board in past reviews.

The Siting Board also notes that BPD's alternative approach of acquiring CO_2 offsets from curtailment or shutdown of existing emission sources could provide a significantly greater level of offsets at a cost similar to that of tree planting arrangements previously accepted by the Siting Board. Thus, offsets from curtailment or shutdown of existing emission sources may be significantly more cost-effective than such tree planting arrangements.

However, the record does not provide information as to the specific offset arrangement BPD would implement to provide its proposed offsets from curtailment or shutdown of existing sources. While there are existing or evolving markets for offsets or emission reduction credits for pollutants, such as NOx, no such market exists or is planned for CO_2 offsets. Further, the Company has not demonstrated that its proposed purchase of CO_2 offsets would lead to source shutdowns or curtailments that would not occur absent such purchase. Thus, BPD has not established that its proposed purchase of offsets from the shutdown or curtailment of existing sources would lead to proven, incremental reductions in CO_2 emissions.

Therefore, the Siting Board concludes that the Company's proposed distribution of a total of 200,000 seedlings, or a comparable tree planting approach, will provide more certain offset of CO_2 emissions from the proposed facility. We note, however, that at the identified distribution rate of 8,000 seedlings per year for the expected life of the facility, the seedling distribution program would provide offsets amounting to only 0.218 percent of facility emissions within five years of facility start-up, i.e., by 2004. Accelerated implementation of the Company's proposed seedling distribution plan would provide an increased measure of mitigation of CO_2 emissions from the proposed facility during the actual years of facility operation.

In a previous review of a generating facility in which a similar contribution to a tree-planting program was proposed over a 40-year period -- the anticipated life of the facility in that review -- the Siting Board determined that a more up-front payment schedule extending over the first three-to-five years of operation would be more appropriate. EEC Compliance Decision, 25 DOMSC at 365. The Siting Board noted that its determination was due, in part, to the fact that earlier payments would help ensure that the CO_2 offsets provided by the carbon uptake of planted trees would be more fully available during the early years of operation of the reviewed facility. Id.

Here, any acceleration of the proposed seedling distribution program must be consistent with BPD's commitment to the Agawam Planning Board to distribute 4,000 seedlings every year over a 25-year period encompassing the proposed facility's anticipated 20-year life. In addition, the cost of 200,000 seedlings is more readily financed over a 25-year period than during the first five years of the proposed facility's operation.

The accelerated distribution of 60,000 seedlings -- half of the seedlings BPD would distribute during the final 15 years of the 25-year program -- would provide more timely offset of CO_2 emissions, while also allowing the Company to meet its seedling distribution obligation to the Town of Agawam. Accordingly, the Siting Board requires BPD to provide CO_2 offsets through an annual seedling distribution program or a comparable tree planting or forestation program, or combination thereof, so as to attain an annual offset level equivalent to 0.385 percent of annual facility emissions within five years of facility start-up and 0.550 percent of annual facility emissions within 20 years of facility start-up.

The Siting Board notes that the CO_2 offset level required herein, although larger than that required in earlier reviews of gas-fired generating facilities, still represents a small percentage reduction amounting to less than one percent of facility emissions. We recognize that BPD has attempted to develop a more cost-effective CO_2 mitigation approach, offsets based on shutdown or curtailment of existing sources, which potentially would allow a significantly larger offset level. The Siting Board encourages BPD and future applicants to pursue the development of a program to provide offsets from shutdown or curtailment of existing sources.[152]

To accept a program based on shutdown or curtailment of existing sources as part of an applicant's CO_2 mitigation plan, the Siting Board would require submission of sufficient supporting information to allow it to conclude that the program likely would lead to proven,

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152 In fact, the Siting Board's general standard of review for CO_2 mitigation requires applicants to present a range of CO_2 mitigation approaches to ensure that all cost-effective approaches have been adequately considered and evaluated. EEC Compliance Decision, 25 DOMSC at 360.

incremental reductions in CO_2 emissions. Specifically, an applicant should demonstrate either (1) that it would acquire CO_2 offsets or emission reduction credits via a market that is operative or planned within an identifiable timeframe, and that is linked to meeting criteria for CO_2 emission limitations or reductions in the United States or other applicable region, or (2) that it would purchase CO_2 offsets that would lead to a source shutdown or curtailment which would not occur without such purchase.

Should BPD develop a specific plan to purchase CO_2 offsets based on shutdown or curtailment of existing sources in an amount equal to one percent or more of the proposed facility's emissions, which offsets would lead to proven, incremental reductions in CO_2 emissions consistent with the criteria set forth herein, the Siting Board would accept implementation of such a plan in lieu of implementation of the required mitigation based on seedling distribution, set forth above. BPD should provide the Siting Board with a detailed description of any such specific plan that it intends to implement.

Accordingly, the Siting Board finds that BPD has established that implementation of its offset plans, with inclusion of the requirements herein, 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 average water use for the proposed facility would be 1.45 mgd during gas firing (Exh. BP-1B at 7-62). The Company indicated that the maximum water usage by the proposed facility would be approximately 1.82 mgd, occurring under peak summer conditions and gas-fired operation (id.).[153] The Company also indicated that water for the proposed facility would primarily be used for process water (id. at 7-62 to 7-63).[154]

The Company stated that a number of features had been incorporated into the design and operation of the proposed facility to reduce its water use, including the use of dry low-NOx combusters for NOx control, the choice of an ion exchange system for the demineralizer system, and reliance on water from the Agawam municipal system for circulating makeup water (Exh. BP-FS-2, at 4-11). The Company indicated that it chose not to incorporate certain additional measures to reduce water consumption of the proposed facility, including recycling of steam cycle blowdown and use of water discharged from the stormwater oil-water separator, because these measures presented other negative impacts to operation of the proposed facility (id.).

The Company provided an analysis comparing water use and other impacts of the proposed facility with dry cooling and wet cooling technology (id. at 4-8 to 4-11). The Company indicated that dry cooling requires no water for an evaporative cooling process (id. at 4-8). The Company stated, however, that use of dry cooling is generally confined to locations where a supply of cooling water is not available, because of the lower plant efficiency relative to evaporative systems and the much higher costs of dry cooling (id.). The Company also indicated that the noise impacts of dry cooling are greater than the noise impacts of wet cooling, and are difficult and costly to mitigate (id. at 4-10).

The Company asserted that the use of dry cooling is unwarranted for the proposed facility, citing the disadvantages of dry cooling and the availability of an adequate water supply for the proposed facility (id.). The Company asserted that the available water supply could meet the water supply needs of the proposed facility without adverse environmental impacts or

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[153] The Company stated that water use for the proposed facility would be slightly higher during oil firing than during gas firing, but that oil firing would likely be limited to the coldest months of the year (Exh. BP-1B at 7-62).

[154] The Company stated that process water included cooling tower make-up water, boiler feedwater, and plant equipment service water (Exh. BP-1B at 7-62 to 7-63).

community impacts to the existing infrastructure, other current or future users of that infrastructure, or the underlying water resources (id.).

i. Primary Site

(A) Water Supply

The Company's preferred option for meeting its water supply needs at the primary site was through the Agawam municipal water supply system ("Agawam municipal system") (Exh. BP-1B at 7-62). The Company stated that the proposed facility would interconnect with the Agawam municipal system at an existing 16-inch line at Franklin Street (Exhs. BP-FS-1(att. A) at 2; BP-FS-2, at 3-73). The Company indicated that the proposed interconnection would require a new interconnect line, approximately 6,300 feet in length, in order to ensure that the water supply needs of the proposed project would be met without adverse impacts on the Agawam municipal system (Exh. BP-FS-2, at 2-33 and 3-73; Tr. 12, at 146).

The Company noted that the Agawam municipal system is supplied by the City of Springfield, and that the main source of the Springfield water supply is the Cobble Mountain Reservoir ("Cobble Mountain") in Blandford (Exh. BP-1B at 7-62 to 7-63). The Company asserted that water withdrawals from Cobble Mountain for the proposed project would not cause the Springfield system to exceed the determined safe yield[155] of Cobble Mountain or any other system supplies, and would not change the frequency of water releases from Cobble Mountain to the Little River (Tr. 12, at 50-53). The Company indicated that the determined safe yield of Cobble Mountain is 55 mgd, and that the City of Springfield's registered MDEP withdrawal is 37.2 mgd (Tr. 10, at 58; Tr. 12, at 92). The Company further indicated that in 1994, the most current year for which data was available, the City of Springfield's average daily water use from Cobble Mountain was 34.71 mgd and its maximum daily water use was 52.20 mgd (Exh. HO-E-41(rev.); Tr. 12, at 64). The Company stated that withdrawals from Cobble Mountain by the City of Springfield have declined in recent years, from a high average

155 The Company stated that the safe yield is the amount of water available to be withdrawn from a given resource without jeopardizing the supply of water itself (Tr. 12, at 52).

daily use of 42.64 mgd in 1988 (Exh. HO-E-41(rev.); Tr. 12, at 64).[156] The Company also stated that withdrawals from Cobble Mountain for the proposed project would be less than the amount of the decrease in withdrawals from Cobble Mountain in recent years (Tr. 12, at 51-53).

BPD indicated that the determined safe yield of the entire Springfield system is 92 mgd (Tr. 10, at 58). The Company stated that it had examined water use projections for communities included in the Pioneer Valley Water Action Plan that rely on the Springfield system (Tr. 12, at 60).[157] These projections indicated that the maximum daily use for customers in the City of Springfield would be approximately the same in 2010 as in 1995 but that water use would increase in surrounding communities that rely on the Springfield system (Exh. HO-RR-67(a)(att.); Tr. 12, at 59, 66).[158]

In the Certificate on the FEIR for the proposed facility, the Secretary of Environmental Affairs cited public comments indicating that the proposed facility would have caused the City of Springfield to exceed its MDEP registered maximum withdrawal based on 1993 usage data (Exh. HO-E-1(sup.)). The Certificate also cited MDEP's comment that the registered maximum withdrawal is well below the reservoir's safe yield, and recommended that municipal planners and MDEP work together to determine whether the addition of the BPD project warrants an increase in the registered withdrawal (id.). MDEP, in comments on the Company's Draft Environmental Impact Report ("DEIR"), also recommended that BPD

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156 The Company indicated that the City of Springfield's maximum daily use declined from a high 76.50 mgd in 1988 (Exh. HO-E-41(rev.); Tr. 12, at 64).

157 The Company indicated that, in addition to the City of Springfield, the Springfield municipal water system presently serves, in whole or in part, the surrounding communities of Ludlow, Agawam, East Longmeadow, Longmeadow and Southwick, and in the past has also sold water to the City of Westfield (Tr. 12, at 66).

158 Maximum-day demand of Springfield customers was projected to be 55.35 mgd in 1995 and 55.61 mgd in 2010 (Exh. HO-RR-67a, Table 3). However, total maximum-day demand in the five surrounding communities was projected to be 24.64 mgd in 1995 and 31.66 mgd in 2010 (id.).

develop a long-term emergency water use plan, which would incorporate alternative sources to relieve the Springfield municipal supply in the event of excessive drought conditions (Exh. BP-FS-3).

With respect to the frequency of water releases from Cobble Mountain to the Little River, Trout Unlimited asserted that the use of approximately 1.5 mgd from Cobble Mountain to meet the water needs of the proposed facility was not advisable (Exh. TU-1, at 1).[159] In support of its assertion, Trout Unlimited submitted a copy of a letter, along with two accompanying photographs of a dry streambed, from Jeffrey J. Balicki, an abutter of the Little River since 1987 (id. at (att. B)).[160] In his letter, Mr. Balicki reported that releases from Cobble Mountain to the Little River, which previously had occurred daily, were discontinued in 1993, and that, thereafter, the Little River "dried up" and "deteriorated both physically and biologically" (id.).

In response, the Company stated that discharges to the Little River have occurred when the water level is higher than the dam at Cobble Mountain and have not occurred when the dam is in drawdown condition, i.e., when the height of the water in Cobble Mountain is below the top of the dam (Exh. TU-1(att. A); Tr. 12, at 50-51). The Company noted that, according to the City of Springfield, intermittent flow conditions have occurred at the Little River since about 1931, when Cobble Mountain was constructed (Exh. TU-1(att. A); Tr. 12, at 44). The Company referred to correspondence from the Springfield Municipal Water Department indicating that, based on the analysis of Springfield's consultants, the ecology of the Little River

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159 Trout Unlimited noted that it neither supported nor opposed the proposed facility (Exh. TU-1, at 1).

160 Trout Unlimited stated that the photographs were taken during the first week of August, 1993, at the Northwest Road Bridge on the Little River in Westfield (Exh. TU-E-5). Trout Unlimited also provided a copy of a portion of a U.S. Geological Survey topographical map, marked to show the location of the two photos accompanying the letter from Mr. Balicki (id.).

had long ago adjusted to an intermittent flow pattern (Exh. TU-1(att. A); Tr. 12, at 50).[161]

The Company also stated that the average daily amount of the proposed facility's water use, approximately 1.5 mgd, would translate to a surface water depth at Cobble Mountain of 2/100 of an inch (Tr. 12, at 79; Tr. 13, at 52-60). Based on this small change in surface water depth, the Company argued that wind direction would have greater impact on the amount of water spilling over the dam than would the daily amount of water withdrawn for the proposed project (Tr. 12, at 79; Tr. 13, at 52-60; Company Brief at 93-94).[162] The Company acknowledged, however, that during the transition from a period of high flow to a period of no release -- a "shoulder period" -- water use by the proposed facility might logically be expected to affect the amount of water spilling over the dam (Tr. 12, at 81-85).

BPD also presented information regarding two alternatives to its preferred option for meeting the water supply needs of the proposed facility at the primary site (Exh. HO-RR-71 (supp.)). The two alternatives were to withdraw water (1) from groundwater wells ("groundwater well option"), and (2) from the Connecticut River, via an intake pipe ("Connecticut River option") (id.; Tr. 12, at 96-121). The Company provided cost comparisons for these three water supply options (Exh. HO-RR-71(supp.)).[163]

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161 The Company asserted that the question of releases from Cobble Mountain to the Little River was not directly related to the proposed project but was, instead, a reservoir management issue between Trout Unlimited and the City of Springfield (Tr. 12, at 123; Company Brief at 94). The Company further asserted that the City of Springfield could both release water to the Little River more frequently and meet the water supply needs of the proposed facility (Tr. 12, at 123; Company Brief at 94).

162 The Company asserted that BPD's water withdrawal from the Springfield system would be less than the decline in withdrawals from the Reservoir, "so there could be no drop in frequency of releases based on what has been observed historically with respect to the correlation between withdrawals from the Reservoir and releases to the Little River" (Company Brief at 94).

163 The Company indicated that over twenty years, the projected costs of the preferred and groundwater well options would not be significantly different (Exh. HO-RR-71 (supp.)). The Company asserted that the lower capital costs of the preferred option would enable the Company to hold down power costs during the proposed facility's early years of

With respect to the groundwater well option, the Company indicated that the on-site aquifer would be inadequate to meet the water supply needs of the proposed project (Exh. BP-FS-2, at 4-13 to 4-16; Tr. 12, at 120-121). The Company stated, however, that the water supply needs of the proposed facility could be met by off-site aquifers in the region (Tr. 12, at 120-121). The Company argued that its preferred option offered several advantages over the groundwater well option (Exh. HO-RR-71(supp.)). First, the Company indicated that it had made a commitment to use the Agawam municipal system for the proposed facility, and that the Town's revenues from the water sales would offset earlier capital investments made to upgrade the Agawam municipal system (id.). The Company also asserted that, in contrast to the groundwater well and the Connecticut River options, the preferred option would not require permitting and would therefore avoid the delays and associated increased costs which might be triggered by permitting (id.).

The Company asserted that the Connecticut River option would be technically feasible but environmentally and economically inferior to the preferred option (Exh. BP-FS-2, at 4-23). In support of its assertion, the Company noted that the Connecticut River option would require the construction of a dedicated water main from the proposed facility to a dedicated intake structure at the bank of the river (id. at 4-19). The Company indicated that it could identify only one feasible site for the intake structure, a parcel of Town land located immediately south of the Bondi's Island Wastewater Treatment Facility ("Bondi's Island"), owned by the City of Springfield (id. at 4-17; Exh. HO-RR-69(supp.); Tr. 12, at 100-117). The Company identified two potential routes, one 4.78 miles and the other 5.35 miles in length, for a water main linking the intake structure and the proposed facility (Exh. BP-FS-2, at 4-19). The Company noted, however, that significant construction-related impacts were associated with each of the routes (id. at 4-20). The Company also indicated that, even with a Connecticut River intake and connecting water main in place, it would likely still rely on the Agawam municipal system to meet potable needs and to supply water to the HRSG (Tr. 12, at 112).

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operation (id.). See Section III.B.3, below.

(B) Water-Related Discharges

The Company indicated that maximum wastewater discharge from the proposed facility would be .238 mgd,[164] and that wastewater would flow from the proposed project at the primary site via a new 100-foot interconnect to an existing on-site main, which is part of the Agawam municipal wastewater treatment system (Exh. BP-1B at 7-65; Tr. 12, at 29-30). The Company indicated that the Town's municipal wastewater treatment system discharged to Bondi's Island (Exh. BP-FS-2, at 3-76). The Company provided information with respect to the capacity of Bondi's Island for the years 1996 through 2020 and to Agawam's contractual allowances for wastewater discharge (id.).[165] The Company asserted that the Agawam municipal wastewater treatment system and Bondi's Island would have sufficient capacity to accommodate discharge from the proposed facility (Exh. BP-1B at 7-65 to 7-67; Tr. 12, at 156-159). The Company further asserted that the design of the proposed facility would ensure minimal impacts to the Agawam municipal wastewater treatment system, other municipal users, and the Connecticut River (Exhs. BP-FS-2, at 3-76; HO-E-34).

The Company described its plans to limit the stormwater impacts of the proposed facility on wetlands and surface water resources (Exhs. BP-1B at 7-57 to 7-58; BP-FS-2, at 3-50, 3-64; HO-E-1(att.) at 2-12 to 2-15). The Company also submitted modifications to its plans to reflect the Agawam Conservation Commission's Order of Conditions ("Order of Conditions") for the proposed facility, as well as comments from state agencies in response to the Company's DEIR (Exhs. HO-E-1(att.) at 2-12 to 2-15; BP-FS-5). The Company indicated that, as part of its plans to control stormwater impacts to surface waters, it would provide an on-site stormwater detention pond designed for a 100-year, 24-hour storm (Exh. BP-FS-2, at 3-64, 3-76). The

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164 The Company asserted that with gas-fired generation, on average, the proposed facility would generate .187 mgd of wastewater (Exh. BP-1B at 7-66).

165 The Company stated that Agawam had a contractual allowance for an average daily flow of 6.1 mgd and a peak flow of 15.4 mgd (Exh. BP-FS-2, at 3-76). The Company indicated that current total system flows averaged less than 3 mgd (id.; Tr. 12, 158-160).

Company noted that, in accordance with the Order of Conditions, the Company would construct a 100-foot discharge channel beyond the end of the discharge pipe from the stormwater detention pond, and that the pipe and channel would extend through the 100-foot buffer zone to the edge of the on-site wetland resource area in the southwestern portion of the primary site (Exh. HO-E-1(att.)).

(C) Construction Impacts

The Company also evaluated potential impacts of construction of the proposed facility at the primary site on water resources, including wetlands (Exh. BP-1B at 7-49 to 7-52). The Company asserted that the proposed facility would be sited outside all on-site wetlands and buffer zones (Company Brief at 84). The Company stated that none of the approximately 2.75 acres of on-site wetlands at the primary site would be disturbed by the footprint of the proposed facility (Exhs. BP-1B at 7-51; BP-FS-2, at 3-45).

With respect to the construction of a water supply interconnect for the proposed project, the Company indicated that a new main from the proposed facility to the Agawam municipal system at Franklin Street Extension would be built entirely within the roadway or shoulder of the plant access road, Moylan Lane, Shoemaker Lane and Silver Street to avoid overland water resource and wetlands impacts (Exh. BP-FS-2, at 3-73). The Company also stated that interconnection with existing on-site electric transmission and sewer lines would not affect wetland resources or associated buffer zones (Exh. HO-S-22(att.)).

With respect to the Tennessee gas interconnect required for the proposed facility at the primary site,[166] the Company stated that the on-site portion of the gas interconnect would cross a 300-foot stretch of buffer zone associated with a wetland area in the southwest portion of the Agawam site (Exh. BP-FS-2, at 3-53). The Company indicated that temporary impacts of construction within a 30-foot swath of wetland buffer along the on-site gas interconnect route,

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166 The Company indicated that Tennessee, rather than the Company, would construct and operate the gas interconnect from the Tennessee mainline to the proposed facility (Tr. 12, at 8-10).

totalling approximately 9,000 square feet, would be limited by the use of all appropriate soil erosion and sedimentation control measures (id.; Exh. HO-E-29; Tr. 12, at 13). The Company stated that Tennessee also would use all appropriate soil erosion and sedimentation control measures to limit any impacts along the 900 to 1,000 linear feet of buffer zone along the route of the off-site portion of the gas interconnect (Exh. BP-FS-2, at 3-53; Tr. 12, at 13-14). The Company asserted that its proposed route for off-site construction of the Tennessee gas pipeline from the proposed facility to the Tennessee Gas mainline and compressor station would minimize impacts to wetlands and associated buffer zones (Tr. 12, at 8-10).

In conclusion, the Company asserted that the proposed facility at the primary site would minimize environmental impacts with respect to all water resources, including wetlands, waterways and groundwater (Exhs. BP-1B at 7-49; Company Brief at 86).

ii. Alternative Site

The Company also evaluated the impacts of the proposed facility on water resources at the alternative site (Exh. BP-1B at 8-8 to 8-17). The Company asserted that the construction and operation of the proposed facility at the alternative site would minimize environmental impacts with respect to water resources, including wetlands, waterways and groundwater (id. at 8-8).

The Company stated that it had identified five water supply options for the alternative site (id. at 8-9). The Company indicated that one option would be to access water from the City of Springfield via its water main at the Southwick/Westfield town line (id.). The Company stated that impacts associated with use of the City of Springfield's water supply would be the same at the alternative site as at the primary site (id.). The Company stated that the four remaining water supply options for the alternative site all would draw water from the same local aquifer, and therefore would have uniform water supply impacts except in respect to water main routing (id.).[167]

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[167] The four alternatives include: using the Southwick municipal water supply; developing a private well; using the Westfield water supply; or using Town of West Springfield

BPD indicated that wastewater from the proposed project at the alternative site would be discharged to a planned new Southwick municipal system, which in turn would discharge to the Westfield municipal system (id. at 8-13).[168] The Company stated that the wastewater interconnect with the planned Southwick municipal sewer system would be routed via roadbed to avoid wetland and buffer zone impacts (Tr. 12, at 33).[169] The Company proposed to minimize stormwater impacts at the alternative site with a stormwater detention pond similar to that at the primary site (Exh. BP-1B at 8-14).

The Company also demonstrated that the proposed facility at the alternative site would be constructed outside all wetlands, and that impacts to wetlands would be limited to temporary impacts associated with construction of the electric and gas interconnects (id. at 8-10 to 8-12).[170] The Company noted that two Flood Zone areas, an on-site area designated Flood Zone B and

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wells located in Southwick (Exh. BP-1B at 8-9).

168 The Company stated that the Town of Southwick planned to have a new sewer system in operation prior to 1999 (Exh. BP-1B at 8-9). The Company indicated that, with the planned Southwick municipal sewer system in place, wastewater from the proposed facility would travel through an on-site interconnect to the Town of Southwick's municipal sewer system, to be discharged to the Westfield Great Brook Pumping Station (Exh. BP-1B at 8-9 to 8-10).

169 The Company noted that the wastewater interconnect would be approximately 25 times longer at the alternative site than at the primary site (Tr. 12, at 30-31).

170 The Company noted that the gas interconnect would cross approximately 9,000 feet of buffer zone, but would be placed in the shoulder and pavement of roadways to limit pipeline crossings to no more than 20 feet of wetlands and 400 feet of buffer area (Exhs. BP-1B at 8-10; HO-RR-65; Tr. 12, at 15-17). The Company maintained that the gas interconnect would be of comparable length and have comparable wetlands and buffer zone impacts at the primary and alternative sites (Exh. BP-1B at 8-12; Tr. 12, at 17). The Company stated that, to minimize impacts to wetlands from the one-mile overhead portions of the electric interconnect for the alternative site, above-ground transmission structures would be placed outside any wetland areas, and the associated transmission line would span wetlands overhead (Exh. BP-1A at 2-7). The Company also indicated that portions of the electric interconnect would be constructed in the railbed of an abandoned railroad right-of-way ("ROW") (Tr. 12, at 26-27).

an off-site area designated Flood Zone A, pose an additional design complication at the alternative site (id. at 8-11; Exh. HO-RR-64; Tr. 12, at 19).[171]

iii. Analysis of Impacts

The Company has demonstrated that its project design incorporates a number of measures to reduce water use at the proposed facility at either the primary or the alternative site. However, the record indicates that dry cooling would significantly reduce the water supply needs of the proposed project. It would also produce a significant increase in noise impacts, and decrease in the efficiency of the proposed facility. The Siting Board will review the balance between water use, noise impacts, and cost in Section III.B.4., below.

With respect to water supply options, the Company has demonstrated that the Springfield municipal system is likely to provide an adequate water supply for the proposed project at either the primary or the alternative site. The Company has further demonstrated that the infrastructure necessary to deliver water to the proposed facility from the Springfield municipal system, with the exception of water supply interconnects, is already in place at both the primary and alternative sites. The Siting Board notes, however, that this water supply option would entail significant consumption of potable water for process uses. Although demands on the City of Springfield's water supply have declined in recent years, the record suggests that the system will face increased demand between 1995 and 2010.

In addition, the Siting Board notes that withdrawal of water from Cobble Mountain may make less water available for the Little River below Cobble Mountain. While the record indicates that flows in the Little River below Cobble Mountain have been intermittent during periods of low-flow since 1931, withdrawals for the proposed project could theoretically lengthen seasonal no-flow periods and reduce spillage over the dam at Cobble Mountain during

[171] Flood Zone A and Flood Zone B are Federal Emergency Management Act designations which identify areas vulnerable to a 100-year flood (Flood Zone A), and a 100- to 500-year flood (Flood Zone B) (Exh. BP-1B at 8-11). The flood zone designations at the alternative site denote areas of potential flooding associated with Slab Brook in Southwick (id.; Tr. 12, at 19).

"shoulder periods."

BPD has argued that management of Cobble Mountain, including the quantity of flow released in the Little River below Cobble Mountain, is a concern within the jurisdiction of the City of Springfield and not a matter over which the Company has control. While the Siting Board recognizes that BPD would be one of the many water system users in several communities which obtain water from Springfield, we also note the considerable quantities of high quality water which the proposed project would demand.

The Siting Board notes that the Certificate on BPD's FEIR recommended that the responsible officials determine whether the proposed project would warrant an increase in the registered maximum withdrawal of the Springfield system from Cobble Mountain. Further, MDEP has recommended that BPD have in place a long-term emergency water use plan, which would incorporate alternative sources to relieve the municipal supply in the event of excessive drought conditions.

The Siting Board recognizes that the City of Springfield is responsible for maintaining the Springfield municipal system, including Cobble Mountain, and for any impacts on other resources, such as the Little River below the dam at Cobble Mountain, which may be affected by management of the Springfield municipal system. However, in light of the considerable quantities of high quality of water which the proposed project would demand, and the projections for increases in overall demand on the Springfield system, the Siting Board directs the Company to work in conjunction with the City of Springfield to identify and to implement, as appropriate, measures to ensure the long-term ability of the Springfield municipal system, including Cobble Mountain, to supply BPD and other customers. Effective measures could include further development of a backup water supply for BPD, such as groundwater wells, but also could include pursuit of programs to conserve water resources used by BPD or used elsewhere in the service areas supplied by Springfield. The extent to which such measures would be necessary may depend on the outcome of the assessment, recommended in the Certificate on BPD’s FEIR, as to whether an increase in registered withdrawals from Cobble Mountain is warranted, and more generally, may depend on whether system water demand increases as projected between 1995 and 2010.[172] The Siting Board finds that, with the implementation of this condition, the water supply impacts of the Company's preferred option on the Springfield municipal system would be acceptable.

BPD has analyzed two other sets of water supply options: the Connecticut River option, and the groundwater well option. The Connecticut River option would reduce consumption of potable water and possible impacts on the Little River. However, the feasibility of this option is greatly constrained by the lack of available sites for construction of a water intake pipe and pumphouse along the Connecticut River. The Company also has shown that the impacts of constructing an approximately 5-mile water transmission line from the intake pipe on the Connecticut River to the primary site would be substantial, and that permitting would present significant difficulties. Consequently the Siting Board finds that the preferred option is preferable to the Connecticut River option.

The Company also has considered groundwater well options at both the primary and alternative sites.[173] Because the Company did not provide specific information as to the likely well locations and interconnection routes, it has not established that the water supply impacts of these options would match or exceed those of the preferred option. However, the Siting Board notes that well withdrawals sufficient to meet BPD's needs could conflict with other water uses, affect nearby surface waters or wetlands, or require lengthy interconnection routes that affect wetland or buffer zone areas. In addition, well options would involve additional permitting requirements, likely including water withdrawal permits. From the standpoint of limiting environmental impacts, the Company's preferred option, relying on the Springfield municipal system, offers a number of potential advantages over the other considered options, including the fact that a supply infrastructure is in place and that the watershed and water volume available to

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[172] The Siting Board notes that such measures to ensure the long-term ability of the Springfield municipal system to supply water would allow the City of Springfield to better maintain the quality of other affected resources, including the Little River below the dam at Cobble Mountain.

[173] These include BPD-developed wells in aquifer areas in the primary site vicinity, and BPD-developed or municipal wells in the large aquifer proximate to the alternative site.

recharge Cobble Mountain are considerable. Thus, any advantage of groundwater well options over the preferred option with respect to water supply and water resource impacts likely would be limited.

The record shows, however, that (1) BPD's reliance on its preferred water supply will result in consumption of large quantities of high-quality water from the Springfield municipal system and may contribute to impacts on associated water resources such as the Little River, and (2) the identified alternative of a groundwater well option might avoid such impacts. The record also shows that the water supply needs of the proposed facility would be significantly reduced with the use of dry cooling. Consequently, the Siting Board finds that the Company has not established that its preferred option results in a minimum environmental impact with respect to water supply and related water resources. The Siting Board will review the balance between water supply impacts, land use impacts, and cost in Section III.B.4., below.

The Company has demonstrated that impacts to all water resources resulting from wastewater and stormwater discharge from the proposed project would be minimized at the primary site. The Company also has demonstrated that wetlands impacts associated with all interconnects would be minimized at the primary site for the proposed project as designed. Accordingly, the Siting Board finds that 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 that, if Southwick's municipal wastewater discharge system is constructed as planned, the impacts from water-related discharges at the primary site would be comparable to those at the alternative site. However, the fact that the Southwick municipal wastewater system has yet to be constructed introduces an element of uncertainty at the alternative site with respect to wastewater discharge which is not present at the primary site.

With respect to construction impacts to wetlands, the Siting Board notes that such impacts at both sites would be temporary and limited by undertaking construction in roadbeds and existing ROWs. However, construction impacts to wetlands would be slightly greater at the alternative site than at the primary site, primarily due to the longer length of interconnects and the greater number of wetlands and buffer zone areas to be crossed by interconnects off-site. Consequently, the Siting Board finds that construction impacts at the primary site would be slightly preferable to those at the alternative site.

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

c. Visual Impacts

The Company submitted a comprehensive evaluation of potential visual impacts of the proposed facility at the primary and alternative sites (Exh. BP-1B at 7-93 to 7-107, 8-48 to 8-52). As part of its evaluation at each site, the Company conducted a viewshed analysis of the surrounding area (id. at 7-95, 8-48 to 8-49). For each viewshed analysis, the Company identified and mapped areas within 1.5 to 2.0 miles of the proposed sites from which the stack of the facility might be visible, assuming a 175-foot stack (id.). From areas where the stack was likely to be visible, the Company selected visual receptor locations, 14 for the Agawam site and 10 for the Southwick site, on the basis of land use, proximity to site, and severity of impact (id.).[174] The Company chose a season without deciduous foliage to take photographs from the identified receptor locations looking toward the proposed facility. The Company then generated a computer-developed view of the facility and stack as they would appear from a given receptor and superimposed the view on the associated photograph (id. at 7-95 to 7-97; 8-48 to 8-49).

The Company also conducted a plume analysis to assess the conditions and frequency under which a plume was likely to emanate from the main stack or cooling tower of the

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174 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. BP-1B at 7-95, 8-48 to 8-49).

proposed facility, and the distance from the proposed facility to which a visible plume would likely extend (id. at 7-102 to 7-106; Tr. 10, at 107-112; Tr. 11, at 16-18). Based on its analysis, the Company asserted that, over the course of a year, during daylight hours, plumes from the main stack with lengths of 100 meters or more would be visible very infrequently and that plumes from the cooling tower of 100 meters or more would be visible even less frequently (Exh. BP-1B at 7-104 to 7-106; Company Brief at 112).[175] The Company indicated that including nighttime hours visible plume calculations would increase annual plume visibility percentages, but asserted that a condensed plume is normally not noticeable at night due to the lack of illumination (Exh. HO-RR-76; Tr. 10, at 108-112; Tr. 13, at 25).[176] In addition, the Company stated that its plume analysis showed that fog and/or precipitation would be present most of the time that main stack and cooling tower plumes of 100 meters or longer were present, reducing further the visibility of the plume (Exh. BP-1B at 7-106).

i. Primary Site

Based on its analysis of computer-developed views from 14 selected receptor locations, the Company asserted that visual impacts of the proposed facility at the primary site would be

175 The Company's analysis indicated that, over the course of a year, plumes from the main stack with downwind lengths of 100 meters or more would be visible 4 percent of daytime hours, plumes with lengths of 50-100 meters would be visible 27 percent of daytime hours, and that plume length downwind and height above stack top would be approximately equal (Exh. BP-1B at 7-104). With respect to plumes from the cooling tower, the Company indicated that plumes with lengths of 100 meters or more would be visible 1.2 percent of daytime hours, whereas plumes with lengths of 50-100 meters would be visible 12.3 percent of daytime hours (id. at 7-105). The Company's analysis further indicated that, for the measured lengths, plume height above the cooling tower would be approximately half of plume length downwind (id.)

176 The Company indicated that a 50-meter-long plume from the cooling tower of the proposed facility would likely be visible 65 percent of the year, including night hours, but only about 13 percent of the year excluding night hours (Exh. HO-RR-76). The Company further indicated that a plume of 100 meters' length would likely be visible eight percent of the year, including night hours, but only one percent of the year excluding night hours (id.).

minimal (Company Brief at 111). The Company stated that, according to its visual impacts analysis, the stack or other structural elements of the proposed facility would be visible from only 23 percent of the viewshed area and that, over most of the impacted area, current views would not be significantly affected (Exhs. BP-1B at 7-98; HO-RR-60 (rev.)).

The Company indicated that views of both facility buildings and stack would be predominant from a receptor at Losito Road and Shoemaker Lane to the west of the proposed facility site (Exh. BP-1B at 7-99). The Company added that views from receptors to the east and south, including points on or near Suffield Street and the southern portion of Shoemaker Lane, as well as to the northwest, in the vicinity of the Saint Anne Golf Course, would be limited to the top of the stack (id. at 7-99 to 7-100).[177]

The Company stated that it had prepared a landscaping plan at the primary site which would further reduce visual impacts resulting from line-of-sight views of the proposed facility from immediately surrounding areas, particularly to the west and east (id. at 7-101 to 7-107; Exh. HO-E-1, at 2-1, fig. 2.1-1). BPD indicated that it would provide additional shrubs or trees to soften the view of the facility from off-site locations, if requested by local residents (Tr. 13, at 91).[178]

Based on its plume analysis, the Company stated that visible plumes of 100 meters or more from the main stack or the cooling tower of the proposed facility would occur infrequently at the Agawam site (Exh. BP-FS-2, at 3-154 to 3-155). In addition, the Company stated that its plume analysis demonstrated that fog and/or precipitation would also be present most of the time that main stack and cooling tower plumes of 100 meters or more were present, further reducing the visibility of the plume (id. at 3-155). The Company asserted that nothing

[177] The Company's analysis indicated that the presence of intervening wooded areas would soften facility views from most vantage points (Exh. BP-1B at 7-98 to 7-100). Principal exceptions include locations near: (1) Shoemaker Lane, west of the site; (2) Silver Street at Almgren Drive, north of the site; and (3) the end of Industrial Lane, southeast of the site (id. at 7-98 to 7-100; Exh. BP-1B, fig. 7.7.2).

[178] BPD stated that it had discussed providing trees and shrubs with the Agawam Planning Board and had made a commitment to do so (Tr. 13, at 91).

in the record supports the proposition that plumes generally cause adverse visual impacts, and that, absent such evidence of effect, the plume conditions projected for the proposed facility -- infrequently-occurring visible plumes often coincident with fog or precipitation -- are consistent with a finding that visual impacts at the Agawam site would be minimized (Company Brief at 112-113). The Company further asserted that the infrequent presence of a plume from the stack and cooling tower will have no negative visual impacts (id. at 113).

Country Estates contended that the proposed facility would not be compatible with the existing visual environment at the Agawam site (Country Estates Brief at 4). In support of its contention, Country Estates cited the height limit of 40 feet for structures in Agawam as defined by Agawam's Zoning by-laws and noted that the height limit would be exceeded by a 175-foot stack or even a 125-foot stack constructed as part of the proposed facility (id.).[179] Country Estates also noted that its property, i.e., the Country Estates Nursing Home building and associated landscaping, was included in the Company's reference to intervening development that would partially obscure the proposed facility from view at the receptor location on Suffield Street just south of Adams Street (receptor location A-4) (id. at 4 to 5; Exh. BP-1B at 7-97, fig. 7.7.6). Country Estates asserted that while the view of a traveller along Suffield Street would be partially obscured by the Country Estates Nursing Home, Country Estates would have a direct and unobscured view, not only of the stack of the proposed facility, but of the plumes emanating from the stack and the cooling tower, including plumes of less than 100 meters' height (Country Estates Brief at 4 to 6).[180]

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179 Both Country Estates and CCBA cited statements regarding the generally rural character of the area surrounding the primary site contained in the decision of the Agawam ZBA denying the Company's request for a special permit (Country Estates Brief at 4; CCBA Brief at 4). See also Exh. HO-RR-62.

180 BPD asserted that, based on elevation differences and intervening wooded area, Country Estates Nursing Home likely would have no view of the proposed facility other than its plume (Tr. 13, at 86). The Company's computer-developed view of the proposed facility from the nursing home location, however, suggests that at least a partial view of the stack will be visible from Country Estates (Exh. BP-1B at fig. 7.7.6).

ii. Alternative Site

Based on its computer-developed analysis of views from 10 selected receptor locations, the Company asserted that visual impacts of the proposed facility at the alternative site would be minimal (Exh. BP-1B at 8-48 to 8-49). The Company noted that, according to its visual impacts analysis, the stack or other structural elements of the proposed facility would be visible from only seven percent of the viewshed area and that, over most of the impacted area, current views would not be significantly affected (id. at 8-48 to 8-52, fig. 8.7.1; Exh. HO-RR-60 (rev.)). The Company also indicated that due to the terrain of the Southwick site and the heavily wooded nature of surrounding areas, substantially fewer and smaller portions of the neighboring community would be afforded views of the proposed facility at the alternative site than at the Agawam site (Exh. BP-1B at 8-52). The Company asserted that visual impacts of the plume at the primary and alternative sites would be comparable (id. at 8-48). The Company further asserted that the alternative site is preferable to the primary site with respect to visual impacts (Company Brief at 114).

iii. Analysis

The record demonstrates that the proposed facility at the primary site is in an area of mixed use (See Section III.B.2.h., below) and that natural and planted vegetative screening as well as existing development would in most sensitive cases soften, if not obscure, a view of the proposed facility and its cooling tower and stack. The record clearly demonstrates that the proposed facility will have visual impacts at the receptor location at Losito Road and Shoemaker Lane, and along portions of Shoemaker Lane west of the site. In addition, Country Estates may have at least a partial view not only of the proposed facility, but of plumes from the stack and cooling tower, when they are present.

With respect to plumes from either the stack or cooling tower of the proposed facility, the Company's analysis demonstrates that visible plumes of 100 meters will occur only a small percentage of daytime hours. The record also demonstrates, however, that smaller plumes from the stack and the cooling tower are likely to be visible with considerably greater frequency during daytime hours. While the Siting Board agrees with the Company that nothing on the record shows the predicted plumes to be harmful, the record also suggests that the visual impact of such plumes may warrant mitigation at specific sensitive receptors.

In a previous review, the Siting Board has required a generating facility proponent to provide selective tree plantings in residential areas up to one-half mile from the proposed stack location to help ensure no more than intermittent visibility of the stack and other facility structures in such areas. NEA Decision, 16 DOMSC at 408-409. Here, in addition to trees and/or shrubs provided as part of its landscaping plan and its seedling distribution program, the Company has expressed a willingness to provide shrubs or trees to soften the view of the facility from off-site locations, if so requested by local residents. Accordingly, consistent with a past review and the Company's stated offer, and in order to ensure that visual impacts are minimized, the Siting Board directs the Company to provide reasonable off-site shrub and tree plantings to help screen the proposed facility from roadways and properties on or near the intersection of Losito Road and Shoemaker Lane, and on or near Suffield Street and the southern portion of Shoemaker Lane, and at other locations within one mile of the proposed facility, as may be requested by property owners or appropriate municipal officials. In implementing its plan for off-site shrub and tree planting, BPD: (1) shall provide shrub and tree plantings 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 Agawam and to all affected property owners prior to commencement of construction; (3) may limit requests from local residents and town officials for shrub and tree plantings to no less than six months after initial operation of the plant; (4) shall complete all such requested plantings within one year after commencement 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 such plantings as necessary to ensure that healthy plantings become established. In addition, the Siting Board encourages BPD 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 condition, and with a 125-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 the visual impacts of a 167.5-foot stack would be considerably greater than those of a 125 foot stack. The Siting Board will review the balance between the visual impacts of a 167.5 foot and the air impacts of a 125-foot stack in Section III.B.4, below.

The record demonstrates that the proposed facility at the alternative site is in an area of mixed use and that natural and planted vegetative screening as well as the terrain of the surrounding area will in most cases, and in all sensitive cases soften, if not obscure, a view of the proposed facility and its cooling tower, stack and plumes. Accordingly, the Siting Board finds that the alternative site would be preferable to the primary site with respect to visual impacts.

d. Noise

i. Primary Site

BPD asserted that the noise generated by operation of the proposed facility at the primary site would not adversely affect residences or businesses, and would be minimized consistent with Siting Board standards (Company Brief at 114-117). BPD further asserted that noise from operation of the proposed facility (1) would produce noise increases at nearby residences within the applicable MDEP ten-dBA limit, while retaining a significantly quieter residential noise environment relative to that in other generating facilities cases reviewed by the Siting Board and (2) would cause no adverse impacts at the nearest property lines based on existing non-residential land uses and zoning and applicable federal guidelines for non-residential exposure (id. at 116-117). BPD asserted that worst-case construction noise levels would be intermittent and temporary, and comparable to the current daytime noise environment in which heavy truck traffic is a common occurrence (Exh. BP-1B at 7-116).

BPD stated that, to be noticeable to people, an increase in average noise level must be greater than three dBA (Tr. 7, at 45). The Company indicated that there are various measures of noise, and noted that the MDEP guideline limiting noise increases to ten dBA is based on a relatively quiet measure of ambient noise that essentially is the residual sound level observed when there are no louder, transient sounds, specifically that level of noise that is exceeded 90 percent of the time ("L_{90}") (Exh. BP-DK-3, at 5, 9). The Company stated that the MDEP ten-dBA limit is applicable at both the nearest residences and nearest property lines, but asserted that MDEP has taken a common sense approach allowing higher increases at non-residential property lines of generating facilities -- if, for example, nighttime exposure would not be a factor because people would not be present and daytime exposure would not exceed non-residential safety guidelines (id. at 9; Brief at 117, citing, Tr. 7, at 26-27).[181]

In support of its position that the proposed facility would adequately minimize noise impacts, BPD provided analyses of ambient background noise levels and expected noise increases resulting from construction and operation of the proposed facility (Exhs. HO-E-26, at 6-1 to 6-15; BP-DK-3).[182] To establish existing background noise levels, BPD provided measurements of daytime and nighttime noise for each of nine receptors, including five residential receptors located at distances of 1,300 to 3,400 feet from the proposed stack, and four property line receptors located at distances of 360 to 590 feet from the proposed stack (Exh. HO-E-26, at 6-1 to 6-10). BPD stated that the principal sources of ambient noise include

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181 BPD indicated that Federal Environmental Protection Agency ("EPA") recommends, as a guideline for avoiding hearing loss, a worker exposure limit of 75 dBA average noise over eight hours, assuming exposure for the remaining 16 hours is significantly less (Exh. HO-E-26, App. B at 11).

182 Measurements of background noise and calculations of facility noise and combined noise are based on a logarithmic scale (Exh. BP-DK-3, at 5). Combined facility and background noise at a receptor often is larger than each of the components -- the calculated facility noise contribution and the background noise -- considered separately (id. at 5-7, 39). For a receptor where the calculated facility noise contribution is significantly louder or quieter than the background noise, however, the facility noise may mask or be masked by the background noise, resulting in a combined facility and background noise that equals or barely exceeds the louder of the separate components. (id.)

mechanical equipment at nearby industrial and commercial buildings, traffic on nearby roadways, and distant transportation at night (Exh. BP-1B at 7-113 to 7-114).

To determine noise impacts from operation of the proposed facility, BPD provided estimates of combined facility and background noise by receptor for daytime and nighttime periods (Exh. BP-DK-3, at 16-40). BPD's analysis indicates that, with facility operation, daytime L_{90} levels would increase by zero to two dBA at residential receptors and by six to 24 dBA at property line receptors (id. at 39).[183] The analysis further indicates that, with facility operation, nighttime L_{90} levels would increase by two to eight dBA at residential receptors[184] and by 20 to 34 dBA at property line receptors (id.; Tr. 7, at 21-22).

BPD maintained that the estimated L_{90} increases at property line receptors in excess of the MDEP ten-dBA limit would not be a concern, because the abutting land at all four such receptors is not currently residential and is not zoned to allow residential use (Tr. 7, at 22-23; Exh. HO-RR-33).[185] With respect to the two receptors at which daytime noise increases would be in excess of ten dBA, the Company indicated that the northeast property line abuts land

183 Two receptors show increases in excess of the MDEP ten-dBA limit, including the northeast property line receptor, which would increase by 24 dBA to an ambient level of 67 dBA, and the southeast property line receptor, which would increase by 14 dBA to an ambient level of 61 dBA (Exh. BP-DK-3, at 39).

184 Three of the residential receptors show nighttime L_{90} increases approaching the ten-dBA limit, including: (1) an increase from 33 to 41 dBA at Moylan Lane, near Shoemaker Lane west of the site; (2) an increase from 31 dBA to 38 dBA at Shoemaker Lane south of the site; and (3) an increase from 31 dBA to 38 dBA at Doane Avenue north of the site (Exh. BP-DK-3, at 39).

185 The Company provided information indicating that existing zoning would allow agricultural use, that residential use for a previously recorded subdivision or lot, and a rest home would be allowed with receipt of a Special Permit from the ZBA (Exhs. HO-RR-33; HO-E-48). Regarding residential use, however, the Company noted that no subdivision plan nor individual lot is recorded for such use in the undeveloped area abutting the proposed site. (Exh. HO-RR-33). See also, Section III.B.2.h, below.

owned by WMECo that is traversed by transmission lines but otherwise vacant,[186] and the southeast property line abuts existing commercial/industrial parcels at the end of Industrial Lane, a cul-de-sac extending from Shoemaker Lane (Exh. HO-E-26, at 6-13; Tr. 7, at 28-29, 34).[187,188] BPD noted that the combined background and proposed facility noise levels during the day, 67 dBA and 61 dBA at the northeast and southeast property lines respectively, would be below an eight-hour work day average of 75 dBA -- the limit recommended by EPA to protect people's hearing (Exh. BP-DK-3, at 39-40). BPD added that the noise contributions from the proposed facility, which also are 67 dBA and 61 dBA at the northeast and southeast property lines respectively, would drop to 55 dBA at points within the abutting parcels 450-750 feet beyond the property line receptors (Tr. 7, at 29-36).[189]

BPD further evaluated its estimates of facility and background noise at residential receptors based on comparisons with (1) similar estimates reviewed by the Siting Board in other generating facility cases, and (2) EPA's recommendation of a maximum day-night noise level

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186 The transmission lines on WMECo's land are located to the north, northeast and east of the location of the nearest proposed facility structure, the cooling tower, at distances of approximately 800 to 1,200 feet (Exhs. BP-2; HO-S-22).

187 BPD stated that the nearest parcel on the west side of Industrial Lane, adjacent to the receptor, is used for a heliport, and the nearest parcel on the east side of Industrial Lane is used for a foundry (Tr. 7, at 28).

188 Although the immediately abutting parcels contain existing commercial or industrial uses or WMECo transmission lines, maps provided by BPD indicate that undeveloped land extends for a distance of a half-mile or more, to the southeast, east and northeast from the locations of the eastern most proposed facility structures and includes parcels owned by a number of other landowners as well as WMECo (Exhs. BP-2; HO-S-6 (att.) S-6b).

189 The expected noise contribution from the proposed facility would be 55 dBA at points within the WMECo property 750 feet beyond the northeast property line receptor, and at points within the Industrial Lane area 450 feet beyond the southeast property line receptor, including a point on Industrial Lane located approximately 1,300 feet north of Shoemaker Lane (Tr. 7, at 30-36). The expected noise contribution of 55 dBA at such points would be 12 dBA above the existing daytime background L_{90} level at the northeast property line receptor, and eight dBA above that at the southeast property line receptor (Exh. BP-DK-3, at 39).

("L_{dn}") of 55 dBA in residential areas to avoid undue activity interference, complaints or annoyance (id. at 92-93; Exh. BP-DK-3, at 3-4, 6, 11; Tr. 7, at 92-93).[190] BPD's witness, Mr. Keast, testified that the estimated nighttime L_{90} at the nearest residential receptor with operation of the proposed facility would be 41 dBA, considerably lower than corresponding worst-case levels for four earlier gas-fired generating facilities approved by the Siting Board (Tr. 7, at 92-93).[191] BPD also stated that the maximum L_{dn} contribution from the proposed facility at a residential receptor would be 47 dBA, well below the EPA 55-dBA guideline (Exh. BP-DK-3, at 40).[192]

With respect to construction noise, the Company provided estimates of long-term average noise by construction phase at the nearest residence, located near Moylan and

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190 BPD indicated that the EPA L_{dn} indicator reflects the average sound level over a 24-hour period with a ten-dBA penalty factor added for a nine-hour nighttime period, to reflect the higher sensitivity to noise of people in their homes at night (Exh. BP-DK-3, at 6). BPD added that, for a steady noise such as that from a generating facility, the nighttime penalty factor results in an L_{dn} that is 6.4 dBA greater than a 24-hour average or other equivalent noise measure without the penalty (Tr. 7, at 55).

191 Mr. Keast cited worst-case nighttime L_{90} levels at residential receptors ranging from 48 to 51 dBA in three reviews of independent power producer projects (Tr. 7, at 92-93). See MASSPOWER Decision, 20 DOMSC at 390; NEA Decision, 16 DOMSC at 401-402; Enron Decision, 22 DOMSC at 208. He added that the worst-case nighttime L_{90} level for the Altresco Pittsfield project, also approved by the Siting Board, was estimated to be 48 dBA (id.).

192 The Company did not provide estimates of combined facility and background L_{dn} levels; however, the Company did provide hourly measurements of average noise over a 24-hour period for a receptor at Moylan Lane, where it intersects with Shoemaker Lane west of the site, and a receptor at Shoemaker Lane south of the site (Exh. BP-1B, fig. 7.8.2 and 7.8.3). BPD's measurements indicate hourly average noise for late evening and nighttime periods ranging from approximately 40 to 55 dBA at both receptors, and hourly average noise for the remainder of the day ranging from approximately 50 to 58 dBA at both receptors (id.). The Siting Board notes that, if the ten-dBA penalty factor for late evening and nighttime periods is incorporated, the Company's measurements indicate an existing ambient L_{dn} of close to the 55 dBA guideline at both receptors (id.).

Shoemaker Lanes 1,300 feet from the southwest property line (id. at 12-14). The Company estimated average noise impacts of 61 dBA during the excavation phase and the finishing phase, with lesser impacts ranging from 50 to 57 dBA during the remainder of the approximately one and one-half year construction period (id.; Exh. HO-V-8, att.). BPD added that facility construction would require ten to 70 construction vehicle round trips per day as well as additional automobile traffic, which would result in noticeable noise at nearby residential locations on Shoemaker Lane (Exh. BP-DK-3, at 15). The Company indicated that construction normally would be limited to the hours of 7:30 a.m. to 4:00 p.m., Monday through Friday (Exh. BP-1A at 7-129).

The Company asserted that its proposed facility is being designed with careful consideration of measures to minimize noise impacts in the surrounding community (Exh. BP-DK-3, at 41). Specifically, to mitigate continuous-source noise, the proposed facility would incorporate: (1) additional muffling above standard amounts in the gas turbine exhaust stream, and full enclosure of the gas turbine exhaust duct and muffler upstream of the HRSG; (2) location of the cooling tower on the east side of the facility, with noise barrier walls or equivalent noise control treatment on the south and north ends and west side of the cooling tower fan deck, and at ground level on the south end of the tower; and (3) acoustic lagging of outdoor piping and valves at the gas metering station (id.; Exh BP-1B at 7-118).

In response to Siting Board staff requests, BPD identified options to further mitigate noise impacts from operation of the proposed facility (Exhs. HO-E-67; HO-E-68; Tr. 7, at 36-40). BPD identified three mitigation measures that could be successively added to reduce the proposed eight-dBA nighttime L_{90} increase at the nearest residential receptor, located at Moylan Lane to the southwest of the facility: (1) enclosure of the cooling tower with eight feet or more of parallel baffles, reducing the Moylan Lane receptor L_{90} increase by one dBA, to seven dBA; (2) installation of high-attenuation louvers on the turbine building ventilation intake, further reducing Moylan Lane receptor L_{90} increase by one dBA, to six dBA; and (3) doubling the size of and enclosing the exhaust duct muffler, further reducing Moylan Lane receptor L_{90} increase by one dBA, to five dBA (Exh. HO-E-64).[193] To further reduce noise impacts to the east of the facility, BPD also identified the option of extending the cooling tower fan deck barrier, currently proposed for three sides of the tower, to the remaining east side, and installing a ground level barrier on the east side (Exh. HO-E-63). BPD indicated that the additional cooling tower barriers would reduce the proposed nighttime L_{90} increase by 11 dBA at the northeast property line receptor, from 34 dBA to 23 dBA, and by ten dBA at the southeast property line receptor, from 28 dBA to 18 dBA (Exh. HO-E-63; Tr. 7, at 21-22).

ii. Alternative Site

The Company stated that the proposed facility, if sited at the alternative site, would include the same noise mitigation features as at the primary site (Exh. BP-1B at 8-53). BPD further stated that it conducted an analysis of estimated facility noise and background noise during daytime and nighttime hours for three noise-sensitive receptor locations -- two residences and a school (id. at 8-53 to 8-55). The Company asserted that noise impacts of the proposed facility at the alternative site would be consistent with the MDEP ten-dBA limit and the EPA 55-dBA guideline, and would be minimized consistent with the Siting Board's standard (Company Brief at 117).

In support of its position, BPD cited results of its analysis indicating that operation of the proposed facility would cause nighttime L_{90} increases of nine dBA at both residential receptors, but result in no nighttime increase at the high school and no daytime increase at any receptor (Exh. BP-1B at 8-58). The Company estimated that average construction noise levels at the nearest residences would be 60 dBA during the erection phase and the finishing phase, with lesser levels ranging from 49 to 56 dBA during the remainder of the construction period (id. at 8-57).

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193 The Company indicated that, to be effective, the three options must be applied successively, in the order identified, because it is necessary to address a source with a louder impact at the identified receptor before addressing a source with a less loud impact (Tr. 7, at 43-44).

With respect to operating noise impacts, BPD acknowledged that it assumed a plant layout corresponding to that at the primary site, and did not optimize the layout to minimize noise impacts for the alternative site surroundings (Tr. 7, at 65). In addition, in response to a request of the Siting Board staff, BPD considered a site-specific option to further mitigate noise impacts at the nearest residence located south of the site at Great Brook Drive, and confirmed that, conceptually, a noise barrier could be placed along a bluff near the receptor to reduce the nighttime L_{90} increase to between five and eight dBA (Exh. HO-RR-36).[194]

The Company noted that the maximum nighttime noise increase at the nearest residences would be slightly greater at the alternative site than the primary site, and therefore concluded that the primary site would be slightly preferable to the alternative site with respect to noise impacts (Company Brief at 118; Exh. BP-1B at 8-59).

iii. 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 guideline. Cabot Decision, 2 DOMSB at 406-407; Altresco-Lynn Decision, 2 DOMSB at 197; 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 such as schools. 1993 BECo Decision, 1 DOMSB at 104-106; Enron Decision, 23 DOMSC at 310-311; NEA Decision, 16 DOMSC at 402-403.

Here, BPD's noise analysis indicates that, for three residential receptors located north, south and southwest of the primary site, facility operation would result in nighttime L_{90} increases of seven to eight dBA above current L_{90} levels, ranging from 31 to 33 dBA. During

194 Mr. Keast stated that a number of residences in the vicinity of the receptor may warrant shielding under the identified option, requiring a barrier 1,300 feet in length (Exh. HO-RR-36; Tr. 7, at 61-64). He indicted that the barrier would need to be sufficiently high to shield second story windows from the noise from the cooling tower (id.).

the day, facility operation would result in L_{90} increases of two dBA or less at all five residential receptors. For primary site property line receptors, all of which abut non-residential land, nighttime L_{90} increases would be well above the ten-dBA limit at all such receptors, while daytime L_{90} would be significantly above the ten-dBA limit for the two receptors located at the northeast and southeast corners of the site.

The Siting Board notes that the proposed eight-dBA increase in nighttime L_{90} noise at the nearest residential receptor would be the largest such noise increase ever accepted by the Siting Board.[195] BPD maintains that the nighttime noise impacts of the proposed facility would be adequately minimized, however, because the maximum contribution of the facility to L_{dn} noise at any residential receptor is well below the EPA 55-dBA guideline, and because the maximum nighttime L_{90} noise at any residential receptor, with operation of the proposed facility, is well below corresponding worst-case impacts in other Siting Board reviews of generating facilities.

The Company's argument regarding lower nighttime L_{90} estimates in this review than in earlier Siting Board reviews appears to have merit, not only for the nearest residential receptor but for all five residential receptors in BPD's analysis. With respect to L_{dn} noise, however, the Company focuses on noise from the proposed facility rather than combined background and facility noise.

In a past review, the Siting Board cited concerns with an estimated combined L_{dn} of 59 dBA at affected residential receptors -- a level clearly over the EPA 55-dBA guideline -- and based on that concern limited L_{90} increases to no greater than five dBA. <u>1993 BECo Decision</u>, 1 DOMSB at 108, 109, 114. Here, BPD's 24-hour measurements indicate residential L_{dn} levels likely would not exceed 55 dBA with operation of the proposed facility, but nonetheless likely would approach that limit. We agree, therefore, that the likely impacts of the proposed facility as reflected in residential L_{dn} levels are acceptable, and note that the estimated residential

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195 In an earlier case, the Siting Board accepted an increase in nighttime L_{90} of seven dBA, from 41 to 48 dBA, but cited its concern that such an increase could result in abutter complaints. <u>NEA Decision</u>, 16 DOMSC at 401-403.

L_{dn} contributions of less than 55 dBA from the facility itself may well have been significant in holding combined facility and background L_{dn} to acceptable levels. We also note, however, that in different circumstances where background L_{dn} already might exceed 55 dBA, it would be important to avoid further increases in either L_{dn} or nighttime L_{90} that might be large enough to result in abutter complaints.

With respect to noise impacts in areas near the northeast and southeast property line receptors at the primary site, the record indicates that daytime L_{90} increases of ten to as much as 24 dBA would extend 450-750 feet into abutting vacant land owned by WMECo and adjacent industrial parcels at the end of Industrial Lane. BPD has demonstrated that the affected areas are not zoned to allow residential use, and also asserts that estimated noise in such areas would meet non-residential guidelines to prevent hearing loss and other concerns.

The Siting Board has not previously reviewed noise increases, nor resultant combined facility and background noise levels, of the magnitude proposed by BPD. Further, although BPD cites instances in which MDEP has accepted noise increases at non-residential property lines that are significantly over ten dBA, it is unclear that MDEP would accept noise increases of the magnitude proposed by BPD, particularly given the inclusion of currently vacant land as part of the affected area. The Siting Board notes that, in addition to the options to extend noise barriers to the east side of the cooling tower, acquisition of land or easements in the affected off-site area also might mitigate the above-mentioned impacts.

The record includes BPD's consideration of options that would further minimize noise impacts from operation of the proposed facility. Such options would reduce expected noise increases that: (1) would be well above the three-dBA threshold for noticeable noise; (2) would approach the MDEP ten-dBA limit at residential receptors and significantly exceed that limit at property line receptors; and (3) would be larger than increases previously accepted by the Siting Board. However, BPD has not proposed to implement options to further minimize noise impacts from operation of the proposed facility, citing cost and limited effectiveness.

Accordingly, the Siting Board finds that the Company has not established that the environmental impacts of the proposed facility at the primary site would be minimized with respect to noise. The Siting Board addresses the appropriate balance between identified options for further mitigation and other cost and environmental factors in Section III.B.4., below.

The record indicates that the residential and other sensitive receptor noise impacts of the proposed facility at the alternative site would be nearly identical to those at the primary site, and that identified options for further noise mitigation at the primary site likely could be applied at the alternative site. Further, the proposed facility at the alternative site would closely abut off-site vacant land on one or two sides, as it would at the primary site on three sides. Despite these similarities, the Company argues that the primary site is slightly preferable, citing residential L_{90} results. At the same time, BPD acknowledges the potential to optimize the plant layout and possibly install a residential noise barrier at the alternative site. Additionally, the Siting Board notes that the overall ability to minimize property line noise impacts may be more favorable at the alternative site because (1) the alternative site is larger than the primary site, and (2) off-site land that would closely abut the facility at the alternative site consists of previously worked gravel quarry area, which may provide a better opportunity than at the primary site for BPD to acquire additional buffer to avoid or mitigate high property line noise impacts. Finally, we note that construction noise levels at the nearest residence would be slightly less at the alternative site.

Accordingly, the Siting Board finds that the primary site would be comparable to the alternative site with respect to noise.

e. Traffic

i. Primary Site

BPD asserted that the construction and operation of the proposed facility at the primary site would have minimal impacts on local traffic conditions and would result in a very small increase in trips in the traffic study area (Exh. BP-1B at 7-121).

In support of its assertions, BPD 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 7-131, 7-135, 7-142). The Company indicated that the majority of construction activity would occur between 7:30 a.m. and 4:00 p.m., Monday through Friday (id. at 7-129).[196] The Company indicated that the maximum number of employees at the site is expected to be 210, which would occur during construction in June 1998 (id.). To help quantify traffic generation, BPD presented a comparison of expected peak-hour levels of service ("LOS")[197] with and without the proposed project for each of the three primary gateway intersections, Silver Street and Shoemaker Lane, Shoemaker Lane and Suffield Street, and Silver Street and Suffield Street (id. at 7-121, 7-129, 7-135).[198] BPD stated that in estimating the number of trips created by the proposed project, it assumed 1.1 workers per car and that 50 percent of the workers would arrive and depart during the morning and evening peak periods (id. at 7-130).[199] The Company indicated that the

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196 The Company stated that there might be limited circumstances when after-hours or weekend construction would be necessary (Exh. HO-E-66). However, BPD indicated that only a small number of workers would be on the site during such periods, and that the off-hours traffic therefore would have no appreciable impact (id.)

197 The Company indicated that the efficiency of traffic operations at a location is measured in terms of LOS (Exh. BP-1B at 7-123). 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 7-123 to 7-124). LOS A through C are considered acceptable operating conditions in an area with characteristics similar to the proposed project study area, under guidelines established by MEPA and the Executive Office of Transportation and Construction (id.).

198 LOS was measured for eight critical intersection movements, including: Shoemaker Lane at Suffield Street -- all moves from South Street, left turn from Suffield northbound, left turn from Suffield southbound, right turn from Shoemaker, and left turn/through movement from Shoemaker; Silver Street at Shoemaker Lane -- left turn from Silver southbound, and all moves from Shoemaker; and Silver Street at Suffield Street (Exh. BP-1B at 7-126).

199 BPD asserted that its assumption that 50 percent of the construction-related traffic would coincide with the morning and evening peak overstates traffic impacts because the morning peak is from 7:30 a.m. to 8:30 a.m., while the construction work-day would begin at 7:30 a.m. (Exh. HO-E-68).

existing peak commuting periods in the area generally are 7:30 a.m. to 8:30 a.m. and 4:45 p.m. to 5:45 p.m. (id. at 7-123, 7-126).[200]

The Company asserted that the LOS analysis shows no adverse project impact on existing traffic conditions during construction (id. at 7-121). BPD stated that the only projected change in LOS due to construction-related traffic would occur at South Street during the morning peak, where service would degrade from a LOS B to a LOS C, which would still be an acceptable level (id. at 7-133).

The Company indicated that three intersection movements at the Shoemaker Lane and Suffield Street intersection currently operate at unacceptable traffic conditions -- LOS E during the evening peak for all movement from South Street, and LOS D and LOS F during the morning and evening peaks, respectively, for the left turn/through movement from Shoemaker (id. at 7-129). The Company asserted that construction-related traffic would not significantly exacerbate the existing unacceptable conditions at this intersection, since LOS for all movements would remain the same under 1998 conditions with and without the proposed project (id. at 7-133, 7-141).[201] BPD stated that the increase in delay associated with the temporary decrease in reserve capacity would not be noticeable to the average commuter (Exh. HO-E-101). BPD indicated that it would develop construction and operation shift schedules to minimize any overlap of facility-related and general traffic patterns at the Shoemaker Lane and Suffield Street intersection (Exh. BP-1B at 7-141).

In addition to employee work trips, the Company indicated that there would be 30 delivery vehicle round trips per day during peak construction (id. at 7-130). The Company

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200 The recorded morning and evening peaks based on actual traffic counts for the three intersections analyzed are: (1) 7:15 a.m. - 8:15 a.m. and 4:00 p.m. - 5:00 p.m. at Shoemaker Lane and Suffield Street; (2) 8:00 a.m. - 9:00 a.m. and 4:15 p.m. - 5:15 p.m. at Silver Street and Shoemaker Lane; and (3) 7:30 a.m. - 8:30 a.m. and 4:15 p.m. - 5:15 p.m. at Suffield and Silver Streets (Exh. BP-FS-2 at App. I).

201 The reserve capacity, which is measured in vehicles per hour, would decrease at the left turn/through movement from the Shoemaker location (Exh. BP-1B at 7-135). The morning peak reserve capacity would decrease from 146 to 118, and the evening peak reserve capacity would decrease from negative 72 to negative 184 (id. at 7-135).

indicated that the regular delivery schedule would be 8:00 a.m. to 6:00 p.m., Monday through Friday, but that it would work to limit deliveries to before 4:30 p.m. (Exh. HO-E-66). The Company further indicated that delivery of very large equipment or pieces would be scheduled for weekend days and that the Company would coordinate such deliveries with the appropriate local officials (id.; Exh. BP-1B at 7-131).

The Company further stated that once the facility is fully operational, 25 employees would work at the proposed facility, spread over three shifts (id. at 7-138).[202] The Company asserted that its analysis shows no significant impacts to intersection capacity conditions when the facility is operational (id. at 7-141). BPD stated that there would be no change in LOS due to facility-related traffic (id. at 7-140).

In the event that oil-burning is necessary, BPD calculated that it would use oil at a rate of approximately 1.4 truck loads per hour, assuming replenishment of oil coincident with its use (Tr. 9, at 46) (See Section II.B.3.d., above). However, the Company stated that it would first draw down its three-day on-site supply of oil, and that in most cases it would not need to operate more than three days continuously on oil, thereby allowing it to replenish the on-site tank on a slower schedule (id.). In addition, BPD asserted that it has committed to both the Town Council and the Agawam Planning Board that it would use a specific preferred route and a backup route for the delivery of fuel oil and chemicals, and that it would limit the delivery of fuel oil and chemicals to between the hours of 9:30 a.m. to 2:00 p.m. to avoid conflicts with the Agawam school bus schedule (Exh. HO-E-67; Tr. 1, at 23).

ii. Alternative Site

BPD asserted that the construction and operation of the proposed facility at the alternative site would have minimal impacts on local traffic conditions, and would result in a very small increase in trips in the traffic study area (Exh. BP-1B at 8-60, 8-72). BPD also

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202 The Company stated that, although the workers would be divided into three shifts, it assumed for the purpose of the traffic study that all 25 employees would arrive during the morning peak and exit during the evening peak (Exh. BP-1B at 7-138).

asserted that the traffic impacts of the proposed facility at the alternative site would be comparable to the traffic impacts at the proposed site in Agawam (id.).

In support of its assertions, BPD 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, based on the same assumptions used for the primary site (id. at 8-63, 8-68, 8-73). BPD indicated that all construction traffic would access the site from Hudson Drive, a limited destination access road that runs north from Route 57 (Exhs. HO-E-70; HO-E-71). BPD presented a comparison of expected peak-hour LOS for two primary gateway intersections, Route 10/Route 202 at Route 57 (Feeding Hills Road),[203] and Route 57 at North Longyard Road (Exh. BP-1B at 8-60, 8-68, 8-73). The Company asserted that the analysis shows no adverse project impact on existing traffic conditions during either construction or operation (id. at 8-60). The Company also conducted traffic counts at the Hudson Drive access, but stated that it did not conduct an LOS analysis since Hudson Drive is a limited access road with limited associated turning movements (Exh. HO-E-71).

The Company indicated that it did not conduct an analysis of Southwick school bus schedules or develop specific strategies to minimize potential traffic conflicts (Exh. HO-E-67). BPD stated that in the event that the proposed facility was to be constructed at the Southwick site, the Company would work with Town and school officials to minimize traffic impacts (id.).

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[203] Feeding Hills Road is a bi-directional roadway that runs east to west from Route 10/202 to Agawam (Exh. BP-1B at 8-61). During the morning peak hour under 1998 construction conditions, 534 cars would be traveling east, with 39 turning onto Hudson Street, and 379 cars would be traveling west, with 59 cars turning onto Hudson Street (id. at Figures 7.9.4, 7.9.5). In comparison, for the primary site, at the morning peak 201 cars would be traveling east along Shoemaker Lane, with 10 cars turning onto Moylan Lane, and 219 cars would be traveling west, with 88 cars turning onto Moylan Lane (id. at Figures 8.9.4, 8.9.5).

iii. Analysis

The record indicates that increased vehicular traffic due to construction and operation of the proposed facility at the primary site would not cause adverse impacts for most key intersection movements in the vicinity of the facility. However, the Siting Board notes that various points of critical movement at the intersection of Suffield Street and Shoemaker Lane currently operate at an unacceptable LOS level during both morning and evening peak periods, most significantly at a LOS of F for the evening peak for the left turn/through movement from South Street.[204] Further, the morning peak hour at this critical intersection begins at 7:15 a.m., a time when a significant number of workers could be expected to arrive for the 7:30 a.m. shift. Thus, the Company's assumption that 50 percent of the workers would arrive between 7:30 and 8:30 a.m. may understate the impact of construction on this intersection.

The Company's assumption also understates the effect of construction traffic during the evening peak period, which falls between 4:00 and 5:15 p.m. at analyzed intersections. Since the construction shift ends at 4:00 p.m., it is likely that nearly 100 percent of employees would depart during the evening peak. Further, the evening peak is when the Suffield Street and Shoemaker Lane intersection experiences its worst LOS.

BPD has stated that it would develop construction and operation shift schedules to minimize arrivals and departures during peak commuter hours at the Suffield Street and Shoemaker Lane intersection. However, the Siting Board notes that, given the anticipated shift schedules, construction traffic will overlap with peak commuter hours in both the morning and evening periods at this already congested intersection. Therefore, the Siting Board requires

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204 Although BPD maintains that unacceptable levels of LOS D, E, and F would be at the same level with either baseline 1998 conditions or with 1998 construction conditions, the proposed project would worsen the already negative reserve capacity at the evening peak by 155 percent at Suffield Street and Shoemaker Lane. While LOS is a method of classifying traffic conditions, the Siting Board notes that significant increases in traffic can result in increased delays and worsening traffic conditions, even while remaining within the same unacceptable classification.

BPD, in consultation with the Town of Agawam, to develop and implement a traffic mitigation plan which includes scheduling to avoid peak travel periods, route modification, or other appropriate measures to minimize construction-related traffic impacts at the Suffield Street/Shoemaker Street intersection during actual intersection peak periods.

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

The Siting Board notes that, in general, increased vehicular traffic due to construction and operation of the proposed facility at the alternative site would not cause significant impacts at key intersections in the vicinity of the facility, and that LOS ratings would remain acceptable for the study area. However, given the heavy traffic on Route 57, the construction-related traffic entering and exiting the site via Hudson Drive has the potential to cause delays in traffic along Route 57. If the proposed facility were to be constructed at the alternative site, the Company should develop a traffic mitigation plan in consultation with Southwick officials. Such a plan might include posting traffic control personnel at the intersection of Hudson Drive and Route 57 during the peak hours of construction and commuter traffic.

Accordingly, the Siting Board finds that the primary site would be comparable to the alternative site respect to traffic impacts.

f. Safety

With respect to safety issues associated with the construction and operation of the proposed facility, the Company asserted that all activities and equipment at the primary or the alternative site would conform to regulatory standards and GEP (Exh. BP-1B at 7-145, 8-76). The Company described a number of measures that would ensure safety during construction, consisting of: (1) requiring contractors to have regulatory compliance programs in place; (2) including provisions in construction contracts that require contractors to adhere to safety and health requirements; (3) including audit, penalty and termination provisions in construction contracts to guarantee full contractor performance relative to health and safety requirements;

and (4) managing and containing chemicals in accordance with all relevant regulations, including containment and off-site safe disposal or re-use of chemical cleaning agents (id.).

The Company asserted that safety and emergency systems designed for the proposed facility would ensure its safe operation at either the Agawam or Southwick site (id.). The Company stated that, among other important safety features, the facility design would include: containment basins or dikes for all hazardous material storage areas; automatic shutdown systems with backup power supply for the turbines and fuel supply systems; and a number of fire prevention and control measures (id.). 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.). The Company also stated that it would prepare a comprehensive "safety and health action plan," which would include the training of all employees in emergency procedures and the coordination of emergency response plans with local emergency support services (id.). The Company stated that, in addition to taking other security measures, it would install a fence to prevent unauthorized individuals from gaining access to the proposed facility during construction and operation (id.).

i. Materials Handling and Storage

The Company indicated that aqueous ammonia, and all other non-fuel chemicals to be stored on site at the proposed facility, would be managed in accordance with all applicable public and occupational safety and health standards (id. at 7-147, 8-76 to 8-77). The Company indicated that, in conjunction with the Agawam Town Council and the Agawam Planning Board, it had developed a delivery schedule and route for fuel oil and chemicals that would minimize potential conflicts with traffic in general and with school bus activity in particular (Exh. HO-E-67 at 1, (att.)). The Company stated that if the proposed facility were built at the alternative site, it would develop a comparably safe delivery schedule and route in cooperation with Southwick town and school officials (id. at 2).

The Company described the steps it had taken to control potential safety and health risks associated with aqueous ammonia, stating that the unloading area would be proximate to the aqueous ammonia storage tank, completely curbed, and designed to hold any spillage from a truck (Tr. 9, at 48-49). The Company indicated that sensors and alarms would be installed as an added precaution in the proposed handling area (Exh. BP-1B at 7-148, 8-76). The Company stated that aqueous ammonia would be stored in one 12,000 gallon tank[205] surrounded by a containment dike to prevent accidental damage from vehicles and large enough to hold the entire contents of the tank without discharge (id.). The Company stated that the containment dike would be covered with floating ball-like baffles to reduce the surface area of an accidental spill from the proposed project and thus the predicted concentrations of an ammonia leak (Exhs. HO-E-1 (att).; HO-E-72). To reduce the potential surface area of a spill still further, the Company agreed during the proceedings to redesign the storage tank to permit construction of a narrower, higher-walled containment dike (Exh. HO-RR-54).

The Company stated that aqueous ammonia would be transported, handled, stored and used in the same manner at the Southwick site as at the Agawam site (Exh. BP-1B at 8-76 to 8-77; Company Brief at 126).

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[206] to determine the likely frequency and location of fogging and/or icing due to evaporative cooling for the proposed facility at both the primary site in Agawam and the alternative site in Southwick (Exh. BP-1B at 7-44 to 7-45, 8-6 to 8-7). The Company stated that it modelled facility emissions over a five-year period and determined that occurrences of ground-level fogging at the rate of one hour per

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205 The Company asserted that one storage tank rather than multiple smaller tanks reduced the likelihood of leaks and operational problems, as well as the frequency of deliveries and associated risks (Tr. 3, at 119-120).

206 The SACTI model is an outgrowth of work sponsored by the EPRI (Exh. BP-FS-2, at 3-36). The Company characterized the SACTI model as "conservative," i.e., as tending to overpredict the incidence of fogging and icing (Tr. 10, at 119-122).

year or greater would be limited to an area within the proposed site boundary (Exh. BP-FS-2, at 3-36). The Company further determined that ground level icing at a location immediately west of the property boundary of the Agawam site would be limited to a single 0.4-hour episode over a five-year period, and noted that this location is not near any public roadway (id.). The Company also stated that natural fog, rain or snow was likely to occur coincident with fogging or icing from the cooling tower (id.).

The Company asserted that impacts from fogging and icing associated with operation of the proposed project at the Southwick site would be comparable to those at the primary site (Exh. BP-1B at 8-7). In support of its assertion, the Company noted that fogging exceeding one hour per year in frequency at the alternative site would likely be limited to one area within 200 meters of the cooling tower, extending southward (id. at 8-6 to 8-7). The Company further indicated that icing would not exceed one hour per year in any direction at the alternative site (id. at 8-7). In addition, the Company stated that natural fog, rain or snow would likely occur coincident with fogging or icing from the cooling tower at the Southwick site (id.).

CCBA contended that dangerous fogging and icing might occur at the proposed facility at the primary site (CCBA Brief at 4-5). CCBA based its assertion in part on (1) analyses and reports of fogging and icing associated with a cooling tower in Iowa; and (2) statements, attributed to victims of traffic accidents in the vicinity of an existing Massachusetts generating facility and cooling tower, which alleged cooling-tower-induced icing at the time of the accidents (id.; Exh. CCBA-2). CCBA also maintained that the evaporative water tower might incubate legionella bacteria and result in illness to abutters in the vicinity of the proposed facility (CCBA Brief at 5). CCBA supported its assertion with a range of newspaper articles and studies written over a twenty-year period that address the occurrence of legionella in a variety of locations and structures distinct from the proposed cooling tower (id.; Exhs. CCBA-4; CCBA-5; CCBA-6; CCBA-7; CCBA-8; CCBA-9; CCBA-10; CCBA-11).

In response to CCBA's assertions, the Company argued, that CCBA: (1) relied primarily on non-record information regarding alleged fogging and icing incidents occurring near other industrial facilities; (2) ignored differences between those facilities and the proposed facility with respect to distances between the affected roads and cooling towers; (3) provided no evidence of nexus between the alleged incidents on roads near the existing facilities and the likelihood that similar incidents would occur near the proposed facility; and (4) did not address the Company's SACTI analysis of the proposed facility's likely fogging and icing impacts (Company's Reply Brief at 4-5).

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. 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 particularly notes the Company's readiness to modify the design of the proposed aqueous ammonia storage tank and containment dike to minimize evaporation of ammonia in case of a spill. Further, the Siting Board notes that BPD intends to develop emergency procedures and response plans similar to those found acceptable in previous Siting Board decisions. See, Cabot Decision, 2 DOMSB at 417; Altresco Lynn Decision, 2 DOMSB at 211; 1993 BECo Decision, 1 DOMSB at 145.

The record demonstrates that fogging and icing associated with the evaporative cooling tower for the proposed facility at both the Agawam and Southwick sites would be limited to on- or near-site locations, and would not occur on public roadways. The Siting Board notes that the record contains no site-specific analysis that would dispute the validity of the Company's analysis of fogging and icing impacts associated with the proposed project at either the primary or the alternative site. However, in order to alleviate public concern in this area, the Siting Board directs the Company, to monitor fogging and icing in the vicinity of the proposed facility, and as necessary, establish a plan in cooperation with local officials, to alert motorists and residents concerning any project-related fogging or icing episodes affecting public safety.

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 comparable to the alternative site with respect to safety.

g. Electric and Magnetic Fields[207]

i. Primary Site

The Company indicated that operation of the proposed facility would produce magnetic field increases associated with (1) the new on-site tie line, which would transmit the project's 252 MW output to the nearby WMECo 115 kV transmission line, and (2) increased power flows on certain existing transmission lines during various load conditions (Exh. BP-1B, att. 7.12.1; Exh. HO-E-76).[208] BPD asserted that the expected increases in magnetic field from the tie line would be minimal or non-existent off the site, with a maximum property line increase of two milligauss ("mG") and no increase at any residence (Company Brief at 128). BPD further asserted that magnetic field increases at the edge of the ROW along existing transmission lines would be insignificant, noting that total magnetic field levels at such locations would remain well below an acceptable maximum of 85 mG recognized by the Siting Board (id.). Finally, BPD indicated that it is pursuing arrangements with WMECo to incorporate double circuit phase configurations that would minimize magnetic field levels along certain existing transmission system ROWs near the site, including (1) the transmission system segment extending to the nearest substation north of the site, in which BPD expects partial

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

208 The Siting Board notes that WMECo'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 EMF levels along existing transmission lines. See, Altresco Lynn Decision, 2 DOMSB at 213; 1993 BECo Decision, 1 DOMSB at 148, 192.

reconductoring would be required, and (2) an additional segment further to the north (id.).[209]

In support of its assertions, BPD provided calculations of magnetic field levels near the site with and without operation of the proposed facility tie line, indicating that the tie line would produce: (1) an increase from zero to two mG at the east property line, abutting WMECo; and (2) no increases elsewhere along the site boundary above existing levels, which range from zero to a maximum of 41 mG nearest the existing WMECo transmission line traversing the site (Exh. BP-1B, att. 7.12.1, Table 1). In addition, based on power flow projections in an interconnection study by BPD's consultant, R.W. Beck, BPD provided calculations of magnetic field levels at the edge of three affected transmission line ROWs in 2000, with and without the proposed project and under peak and off-peak conditions (id., Table 2; Exh. HO-V-19(att.)). BPD's calculations show that the greatest increases in magnetic field would be (1) for peak load periods, an increase from 13.4 mG to 26.8 mG on the transmission system segment between the site and the North Bloomfield substation, to the southwest in Connecticut, and (2) for off-peak periods, an increase from 13.4 mG to 36.9 mG on the segment between the site and the South Agawam junction, north of the site (Exh. BP-1B, att. 7.12.1, Table 2).[210]

Regarding the calculated peak load increase in magnetic field levels between the site and the North Bloomfield substation, BPD asserted that such conditions would occur infrequently, for a few minutes to an hour each year (Exh. HO-E-76). BPD's witness, Mr. Roberts, indicated that the affected segment extends through a primarily rural area with occasional street crossings and a few homes near the ROW (Exh. HO-S-22; Tr. 13, at 84-85).

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209 The Company indicated that its analysis shows the proposed tie line also would result in little or no increase in off-site electric field levels (Exh. BP-1B, att. 7.12.1). BPD added that there would be no increase in electric field levels along existing transmission line ROWs with operation of the proposed project because operating voltages would remain the same (id.).

210 The Company indicated that both segments consist of two three-phase circuits in which similar phases have been connected together to form a single transmission line (Exh. HO-RR-2). The segment to the South Agawam junction is one-half mile in length, and the segment to the North Bloomfield substation is approximately ten miles in length (id.; Exh. HO-V-19(att.), Attachment C).

Regarding the calculated off-peak load increase in magnetic field levels between the site and the South Agawam junction, BPD indicated that, if the existing line is reconductored and operated in a double circuit configuration with reversed phases, as BPD recommends, the magnetic field level would be 10.7 mG rather than 36.9 mG, resulting in a reduction rather than an increase in magnetic field levels due to the proposed project (Exhs. BP-1B, att. 7.12.1; HO-E-76; HO-E-104). BPD indicated that reversing phases in the reconductored line would result in similarly reversed phases with a corresponding reduction in magnetic field levels for the existing double circuit line continuing north from the South Agawam junction to the Silver Street substation, one mile north of the site (Exhs. HO-S-6; HO-S-22; Tr. 1, at 32-34; Tr. 13, at 78-79). The ROW between the site and the Silver Street substation crosses Silver Street, where there are nearby residences, but otherwise traverses predominantly undeveloped land (Exhs. BP-1B, Figure 7.6.2; HO-S-22; Tr. 1, at 32-34).

The Company indicated that the double circuit transmission line segment north of Silver Street substation, extending approximately three miles to the Agawam substation near the Westfield River, also would show significant increases in off-peak power flow with operation of the proposed project (Exh. HO-V-19(att.), cases A-19, A-20; Tr. 13, at 79, 83). BPD stated that reverse phasing likely could be accomplished without reconductoring in the segment between Silver Street and the Agawam substations, and added that it has requested that WMECo consider modifications to implement such reverse phasing (Exh. HO-RR-80; Tr. 13, at 80; Company Brief at 129). Mr. Roberts testified that he had walked that ROW segment, and that it traverses some built-up areas that include 20 to 30 homes abutting the ROW (Tr. 13, at 81-82).

ii. Alternative Site

The Company stated that the proposed facility, if sited at the alternative site, would produce magnetic field increases associated with (1) the 4.5-mile tie line, which would transmit the project's 252 MW output to the WMECo 115 kV transmission line southwest of the site, and (2) increased power flows on certain existing transmission lines during various load conditions (Exh. HO-E-76). BPD asserted that magnetic field increases at the site boundary and at the edge of the ROW along the tie line and existing transmission lines would be insignificant, noting that total magnetic field levels at such locations would remain well below an acceptable maximum of 85 mG recognized by the Siting Board (id.).[211] BPD asserted that the primary site is slightly preferable to the alternative site with respect to EMF impacts (Company Brief at 130).

In support of its assertions, the Company indicated that the tie line would produce maximum magnetic field levels at the edge of the ROW of 3.7 mG along the 3.5-mile underground portion and 57.2 mG along the one-mile overhead portion (id., Table 1). BPD also provided calculations showing that the greatest increases in magnetic field at the edge of existing transmission line ROWs would be (1) for peak load periods, an increase from 2.5 mG to 13.7 mG between the tie line and the North Bloomfield substation, to the south in Connecticut; and (2) for off-peak periods, an increase from 9.9 mG to 29.0 mG between the tie line and Grandville junction, to the north (id.).

iii. Analysis

In a previous review of proposed transmission line facilities which included 345 kV transmission lines, 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 field and magnetic field levels would show little or no change with operation of the tie line, and would remain well below the levels found acceptable in the 1985 MECo/NEPCo Decision. In addition, a portion of the regional 115 kV transmission line owned and maintained by WMECo, and into which the proposed facility would interconnect,

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211 The Company asserted that the tie line also would not result in a significant increase in electric field levels at the site boundary or the edge of the tie line ROW, citing an expected increase of 0.38 kV/meter at the edge of the ROW (Exh. HO-E-76). BPD added that there would be no increase in electric field levels along existing transmission line ROWs with operation of the proposed project because operating voltages would remain the same (id.).

likely would be reconductored by WMECo as part of such interconnection using a phase configuration that would minimize any magnetic fields between the site and Silver Street substation as a result of operation of the proposed project. Finally, as part of its interconnection agreement discussions with WMECo, BPD has and will continue to pursue modifications by WMECo to the phase configurations of existing transmission lines between WMECo's Silver Street and Agawam substations, so as to minimize any magnetic fields along such transmission lines as a result of operation of the proposed project.

The record demonstrates that the Company's interconnection plans include reasonable efforts to implement measures to minimize EMF impacts on portions of the existing transmission system affected by the proposed facility. Based on the Company's representations, the Siting Board expects that, as part of any BPD interconnection agreement with WMECo that provides for modifications to existing WMECo lines serving the site, BPD would seek inclusion of the transmission designs discussed herein to minimize magnetic field impacts through the phase configuration of such lines serving the site.

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

Operation of the proposed facility at the alternative site would result in greater overall EMF impacts than at the primary site, based on the incremental exposure along the 4.5-mile tie line, particularly the one-mile overhead portion thereof. Accordingly, the Siting Board finds that the primary site would be preferable to the alternative site with respect to EMF impacts.

h. Land Use

i. Primary Site

The Company asserted that the proposed facility at the primary site is fully compatible with land use and development in the surrounding area (Exh. BP-1B at 7-90). BPD further asserted that the proposed facility would be compatible with current land use characteristics and zoning for the site and surrounding areas, and would be consistent with relevant Agawam and regional development objectives (id. at 7-82).

BPD stated that the project site is an approximately 40-acre undeveloped site located in an area designated as the Shoemaker Industrial Park ("Industrial Park") (id. 7-83; Exh. HO-E-51).[212] The Company indicated that the portion of the site to be developed, ten acres in area, is primarily an open grassy field currently used as a private small aircraft runway and for cultivation (see Exhibit C, map of site) (Exh. BP-1B, at 7-68, 7-83, Figure 7.6.3). The remainder of the site consists of woods and wetland, extending approximately 1,500 feet south to frontage on Shoemaker Lane (id.). BPD asserted that the size of the site is sufficient to accommodate the proposed facility and its ancillary components and to provide a significant buffer for surrounding land uses (id. at 7-90).

The Company asserted that the area within a one-mile radius of the proposed facility site can be characterized as mixed-use, consisting primarily of commercial and industrial development in the Agawam Industrial Park -- a second industrial park in that area -- and along Shoemaker Lane and Silver and Suffield Streets (id. at 7-88). The Company categorized the abutting land uses as industrial operations, vacant industrially zoned land, and commercial properties (id. at 7-86). Specifically, BPD reported that the property is bounded to the north and east by undeveloped, open and heavily wooded land owned by WMECo, to the southeast by a construction company and other commercial and industrial properties, to the southwest by a bus company, to the west by a residence, church, and undeveloped parcels, and to the northwest by SCBI (id. at 7-86 and 7-87).[213] The land use map provided by the Company indicates that within a half-mile radius of the proposed facility site, the land use is approximately 50 percent open or vacant, 25 percent industrial/commercial, and 25 percent residential or agricultural (id. at Figure 7.6.3). Within the next half-mile ring, land use is

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212 The Industrial Park is bounded by Shoemaker Lane, Silver Street, and Suffield Street (Tr. 4, at 24). The Industrial Park is not fully occupied; however BPD reported that Agawam is currently recruiting new businesses to the Industrial Park (Exh. HO-E-51). The largest single landowner in the Industrial Park is WMECo (Tr. 13, at 118). The Park is not subject to any guidelines or covenants except for the applicable Agawam Zoning By-laws (id. at 114-115).

213 SCBI is presently the only development on Moylan Lane (Exh. BP-1B, at 7-87).

mixed with approximately equal parts industrial/commercial, residential, agricultural, recreational, and open/vacant property (id.).

BPD stated that significant areas of residential development are located principally to the east of the proposed site, across Suffield Street, and that residences are intermixed with commercial and industrial development along Shoemaker Lane, Suffield and Silver Streets (id.).[214] The Company indicated that approximately 85 residences are located within a half-mile of the nearest proposed facility structure, and approximately 280 residences are within one mile of a proposed facility structure (Exh. HO-E-47).[215] The Company stated that the nearest residence is located approximately 1,200 feet southwest of the closest proposed facility structure, on Shoemaker Lane across from the entrance to Moylan Lane (id.). Further, the Company stated that the nearest residence to the site property line is located across Shoemaker Lane, approximately 100 feet to the south of the site (id.).

BPD asserted that power generation is allowed by right at the proposed site under the applicable zoning district, Industrial B,[216] which allows any industrial purpose not expressly excluded as hazardous or offensive to the surrounding community (Exh. BP-1B, at 7-89). BPD explained, however, that the generation building, fuel oil storage tank, demineralized water storage tank, main stack and cooling tower exceed the 40-foot height allowed in an Industrial B district (id.). Therefore, the Company filed an application seeking a Special Permit[217] in

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214 The land use map provided by the company indicates that the majority of the residential land use within a half-mile radius of the site is located on the south side of Shoemaker Lane (Exh. BP-1B, at Figure 7.6.3).

215 These numbers were estimated based on the 1983 Agawam Board of Assessors Map, the 1979 USGS West Springfield Quadrangle map, an April 1990 aerial photograph, and field observations (Exh. HO-E-47).

216 The Town of Agawam has ten classes of zoning districts, including two industrial, five residential, one agricultural, and two business classifications (Exh. HO-E-48S).

217 Mr. Roberts stated that BPD filled out the special permit forms at the direction of the Agawam zoning officer, in response to the Company's request for approval to exceed the 40-foot height limitation (Tr. 11, at 244).

accordance with Section 180-63 of the Agawam Zoning By-laws.[218] BPD's application for a Special Permit was denied on January 4, 1996 (Exh. HO-RR-62; Company Brief at 108).[219] BPD stated that it received site plan approval from the Agawam Planning Board on September 7, 1995 (Exh. BP-FS-6).

The area abutting the proposed site also is zoned Industrial B, with the exception of the south side of Shoemaker Lane near the southern boundary of the proposed site, which is zoned Residence A-3 (Exh. BP-1B at Figure 7.6.4). Within a one half-mile radius of the site, the area is zoned primarily Industrial B; however, there are residentially zoned areas south and southwest of Shoemaker Lane (id.).

The proposed site includes 10 acres of land that are classified by the Massachusetts Department of Food and Agriculture as agricultural land, the loss of which must be mitigated or compensated under G.L. c. 61A (Exh. HO-E-43).[220] BPD reported that it has committed to lease five acres of undeveloped land located on the northern portion of the site for the highest and best agricultural use (Exh. HO-E-1, (att.) at 2-6; Tr. 13, at 27). In addition, any topsoils removed from this area during development would be used first for BPD's landscaping plan and then, if available, would be donated to local farms or greenhouses (Exh. HO-E-1, (att.) at 2-8).

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[218] Section 180-63, entitled "Height regulations," states: "Industrial buildings shall not exceed two (2) stories, forty (40) feet in height, except with approval of the Board of Appeals after a public hearing. These provisions shall not apply to required equipment appurtenant to industrial buildings, except that smokestacks, water tanks, grain elevators and the like are not permissible except after approval of the Board of Appeals after a public hearing" (Exh. HO-E-48 (att.)).

[219] The record indicates that the Agawam Zoning By-laws operate pursuant to authority granted under G.L. c. 40A, §§ 1-22 (Exh. HO-E-48). G.L. c. 40A, § 9 states that "a special permit issued by a special permit granting authority shall require.... a unanimous vote of a three member board." Two members of the Agawam Zoning Board of Appeals voted in favor of the application and one opposed it (HO-RR-62).

[220] The ten-acre area is located in the northern portion of the proposed site (Exh. HO-E-1 (att.). at 2-6). Approximately three acres would be used for active development, and the remaining area would stay undeveloped and serve as a buffer (id.)

The Company stated that it would provide five acres of land on the eastern portion of the proposed site for community use (id.; Tr. 13, at 28). Further, the Company stated that it has committed to provide the Town with the right to access and use the southern portion of the site for recreational purposes (Exh. HO-E-46). The Company stated that the southern portion is wooded with the exception of an acre of cleared land in the southernmost portion of the site, and that it will be open to Town use with the provision that the Town not remove any trees that are serving as a visual buffer (Tr. 13, at 29).

BPD asserted that the proposed project would not adversely affect property values, and in fact should enhance property values due to the proposed in-lieu-of-taxes payments to the Town (Exh. CCBA-13; Tr. 11, at 182-183). Further, the Company asserted that analyses conducted in Massachusetts communities with power plants show no negative impact on property values, and in fact demonstrate that property values have increased beyond the general increase that would be expected in communities without power plants (Tr. 11, at 182-183).

The Company reported that electric transmission and sewer easements cross the northern portion of the proposed site (Exh. BP-1B at 7-69). BPD stated that the electric and sewer interconnections would occur on-site, and that gas and water interconnects would extend within roadways, thus minimizing land use impacts (id. at 7-90, 7-91).

BPD asserted that the construction of the proposed facility would have no adverse impact on historical or archeological properties (id. at 7-86). An intensive archaeological survey of the project site by Public Archaeology Laboratory, Inc. determined that the property was not an historic period site (id. at 7-84, 7-86).

Country Estates argues that the primary site is not an appropriate location for the proposed facility due to the surrounding land uses, and argues that the land use impacts of the proposed facility are not acceptable (Country Estates Brief at 2, 3). Citing the ZBA decision denying the Special Permit, Country Estates asserts that: (1) the proposed facility would at times be a nuisance or potential hazard to vehicle or pedestrian safety; (2) the use of a smokestack in excess of 125 feet, a cooling tower in excess of 40 feet, and an oil storage tank are so objectionable as to be against the public interest and/or detrimental to the character of the neighborhood; and (3) the proposed facility is located in an area of residences, banquet and entertainment facilities, a nursing home, and commercial facilities, none of which have the type of equipment associated with the proposed facility (id. at 3).

CCBA argues that the proposed facility is in close proximity to abutters, and that the buffer zone between the proposed facility and abutters is not acceptable (CCBA Brief at 3). CCBA also argues that the proposed facility would have a detrimental effect on surrounding property values, citing language from an appraisal concerning marketability of a residence located near the NEA generating facility in Bellingham (id.).[221] The appraisal contained a location depreciation adjustment of seven percent due its the close proximity to the NEA generating facility (Exh. CCBA-16).[222]

CCBA argues that the development of the proposed facility is inconsistent with land use objectives outlined in two Agawam planning documents, "Industrial Planning Study"[223] and "Coming Together for Consensus: A Working Statement of Goals and Objectives to Guide Agawam into the Future" (CCBA Brief at 4; Exh. L-RR-1). CCBA stated that the proposed

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[221] The appraisal states "the subject is located in close proximity to an electric power plant. The plant causes noise and an inferior view, therefore is considered an adverse influence to the neighborhood. It is the appraiser's opinion that the close proximity of this plant would affect the marketability of the homes in this neighborhood" (Exh. CCBA-16; CCBA Brief at 3).

[222] CCBA also provided a letter from the owners of the NEA facility to the mortgage company that had contracted for the appraisal of the property (Exh. CCBA-16). NEA disputed the appraisal and pointed to steps it took to ensure that property values would not be affected by the facility including: (1) construction of earthern berms and trees around the site; (2) gifts to individuals and neighborhood groups in excess of $100,000; (3) personalized school bus routes; and (4) direct contributions of over $1 million to the Town of Bellingham to maintain community services (id.). In addition, the Siting Board notes that NEA was ordered by the Siting Board to provide site specific mitigation through off-site tree planting. NEA Decision, 16 DOMSC at 71-72.

[223] The Industrial Planning Study reports that the Silver, Shoemaker, Suffield triangle is designed to provide locations for light industrial activities (Exh. L-1). The Industrial Planning Study was commissioned by the Agawam Economic Development Industrial Corporation and conducted by an independent consultant in April 1989 (id.).

facility is not in compliance with the Agawam Zoning By-laws since it exceeds the 40-foot height limitation (CCBA Brief at 4).

Finally, CCBA argues that the primary site for the proposed facility is home to a rare and endangered species, the Eastern Box Turtle ("box turtle"), and that construction at the site will adversely impact the box turtle's habitat (Tr. 11, at 278; CCBA Brief at 7). In support of its contention, CCBA presented a witness, Amy J. Ringuette, who testified that she had observed box turtle specimens in the vicinity of the primary site on a number of occasions (Tr. 11, at 294). The witness indicated that her observations of the box turtle occurred at the edge of fields close to woodlands or in the woodlands themselves, and that the locations of the sightings were close to or bordering the primary site (id. at 299). The witness testified that fields and woodlands are the box turtle's prime habitat, but did not, under examination by the Company, disagree with the Natural Heritage and Endangered Species Program's ("NHESP")[224] conclusion that the box turtle's preferred habitat is open deciduous forest (id. at 300, 304).[225] Ms. Ringuette testified that the range of the box turtle was two to eleven miles, but indicated that, as demonstrated by additional information provided by CCBA, the range of the box turtle was a matter of dispute (id. at 313).[226]

In response, the Company's witness, Frederick Sellars, testified that the Company had received letters from the U.S. Fish and Wildlife Service and NHESP indicating that neither agency was aware of any occurrences of rare plants or animals at the primary site (id. at 113;

224 The NHESP is a program of the Massachusetts Division of Fisheries and Wildlife ("DFW").

225 In fact, Ms. Ringuette indicated that she had contacted the NHESP in addition to the Agawam Conservation Commission and CCBA regarding her observations of the box turtle (Tr. 11, at 276, 322).

226 Material submitted by CCBA estimated the home range of the box turtle at 100 to 750 feet (Tr. 11, at 312).

Exh. BP-FS-2, at (att.) D).[227] Mr. Sellars further testified that the box turtle has a limited home-range movement of from 150 to 750 feet; that a portion of the primary site was deciduous forest; and that the box turtle, if at the primary site, was likely to be located in the area of deciduous forest, its preferred habitat (Tr. 11, at 116-118). Mr. Sellars stated that construction for the proposed facility was not planned for the forested area, and that the parcel of deciduous forest would be maintained as a buffer area after construction of the proposed facility (id.). The Company therefore argued that, constructing the proposed facility at the primary site as planned would, by preserving open deciduous forest, mitigate impacts to the habitat of the box turtle (id. at 117).

ii. Alternative Site

The Company asserted that the proposed facility at the alternative site is fully compatible with land use and development in the surrounding area (Exh. BP-1B at 7-90). BPD further asserted that the proposed facility would be compatible with current land use characteristics and zoning for the site and surrounding areas, and would be consistent with relevant Town of Southwick development objectives (id. at 8-42).

BPD stated that the alternative site is an approximately 200-acre site located within one of only two main industrially zoned districts in the Town of Southwick (id. at 8-23, 8-46). The Company also stated that the portion of the site to be developed currently operates as part of a sand and gravel business (id. at 8-43).

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[227] In response to a request by the Siting Board, the Company inquired of NHESP as to whether a re-evaluation of that agency's findings would be necessary in light of Ms. Ringuette's filed observation with the NHESP, dated December 21, 1995 (Exh. HO-RR-75 (supp.)). The Company provided a copy of a communication sent to the Massachusetts Environmental Protection Act office on February 27, 1996, from the DFW (id. at (att.)). In its communication, the DFW indicated that the design of the proposed BPD facility appeared to avoid impacts to the box turtles and their habitat (id.). The DFW also stated that it would require the Company to build a fence before beginning work on the proposed facility to prevent box turtles from entering the construction area (id.).

The Company categorized the land uses that abut the site as the remainder of the sand and gravel operation, undeveloped open space and wooded land, and residential properties (id.). Specifically, BPD reported that the property is bounded to the north, east, and southeast by undeveloped and heavily wooded areas, to the south by the sand and gravel removal area, to the south along Hudson Drive by limited light industrial development, to the southwest by undeveloped parcels, and to the west by scattered residential properties (id. at 8-43, 8-44). The land use map provided by the Company indicates that land use within a half-mile radius of the site is approximately 60 percent agricultural/open/vacant, 20 percent industrial/commercial, and 20 percent residential (id. at Figure 8.6.1). Within the next half-mile ring the land use is approximately 75 percent agricultural/open/vacant, 15 percent residential, and 10 percent industrial (id.).

BPD stated that the closest significant residential development is located to the south of the site beyond the sand and gravel operation (id. at 8-44). The Company indicated that there are approximately 100 residences located within a half-mile radius, and approximately 260 residences within a one-mile radius of the nearest proposed facility structure (Exh. HO-E-47).[228] The Company stated that the nearest residence is located on Great Brook Drive approximately 1,000 feet southwest of the nearest proposed facility structure (id.). Further, the Company stated that the nearest residence to the site property line is at the end of Sam West Road, approximately 150 feet from the site boundary (id.). The Company reported that there are three schools located along Route 57, the Woodland Elementary School, Powder Mill Middle School, and the Tolland Regional High School, all within approximately 4,000 to 4,500 feet of the proposed alternative facility site (Exh. HO-E-53).

The site is zoned Industrial Restricted, which requires that a Special Permit be granted by the Town of Southwick Planning Board before the proposed facility could be constructed (Exh. BP-1B, at 8-45). The area surrounding the proposed site is zoned Industrial Restricted,

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228 The number of residences was approximated based on the Southwick Board of Assessors Map, the 1979 USGS Southwick Quadrangle map, and field observations (Exh. HO-E-47).

with the exception of the eastern area, which is zoned Agricultural and Conservation (id.).[229] Within a one-half mile radius of the proposed facility at the alternative site, the area is zoned primarily Industrial Restricted and Agricultural and Conservation (id. at Figure 8.6.2).

BPD stated that off-site electric transmission and natural gas interconnects would be required, and that the electric interconnect would be 4.5 miles in length and the gas interconnect would be approximately one mile in length (id. at 8-24, 8-25). The electric interconnect route would begin as an overhead line from a WMECo substation, traveling overland to the east for approximately one mile to a former Penn Central Railroad right-of-way ("ROW") (id. at 8-24). From there, the interconnect would become an underground line for approximately 3.5 miles, traveling in a northerly direction to the proposed alternative site (id.). The Company asserted that since the proposed electric transmission interconnect would primarily follow a former railroad ROW, land use impacts would be minimal (id. at 8-36). The gas interconnect would begin one mile south of the proposed alternative site, traveling along Hudson Drive to Route 57, to a former railroad ROW, where it interconnects after a quarter of a mile with the Tennessee mainline (id. at 2-7, 2-8).

BPD asserted that the construction and operation of the proposed facility at the alternative site would be comparable to construction and operation at the proposed site with respect to land use impacts and community resources (id. at 8-47).

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. Here, the record indicates that the primary site and surrounding areas are zoned for industrial use, that the abutting uses are a mixture of light industrial and commercial, and that the area within a mile radius of the primary site is divided equally between industrial, commercial, residential, and agricultural/vacant land.

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229 A small portion of alternative site, located to the east, is zoned Agricultural and Conservation, but it is not within the development footprint (Exh. BP-1B at 8-45).

The record also demonstrates that BPD's site selection process was designed to minimize the land use impacts of the chosen site (see Section III.A, above). The primary site was recommended for this purpose by the Town of Agawam, and the proposed facility is an allowed use under the Zoning By-laws of the Town of Agawam. Electric, gas, water and sewer interconnections at the primary site would require minimal off-site land, further limiting land use impacts. In addition, the Company has agreed to protections for agricultural land at the primary site.

Intervenors in this proceeding have raised a number of land use-related concerns regarding the primary site, including issues of safety, visual impacts, consistency with land use objectives and existing uses, adequacy of buffering, and property values. The Siting Board addresses visual and safety impacts issues in Sections III.B.2.c and III.B.2.f, above.

With regard to the consistency of the proposed facility at the primary site with land use objectives, the Siting Board notes that the proposed cooling tower and stack exceed the 40-foot height limitation in the Agawam Zoning By-law. While this has been true of most generating facilities previously reviewed by the Siting Board, many of these were to be located in the immediate vicinity of existing stacks or structures of a similar scale. See, e.g., Cabot Decision, 2 DOMSB at 420; Altresco Lynn Decision, 2 DOMSB at 199, n. 232; MASSPOWER Decision, 20 DOMSC at 396. Here, the proposed structures are considerably taller and of a different scale than existing structures in the surrounding area. The Siting Board notes that BPD's petition to the ZBA for a Special Permit to exceed the 40-foot height limitation was denied, and that BPD must now seek appropriate relief before it can receive a building permit.[230]

However, the Siting Board also notes that the primary site was recommended to BPD

230 This is the first Siting Board review of a generation facility where a petitioner was refused the required zoning-related approval by the affected municipality to construct its facility to its basic specifications. The Siting Board notes that the issuance of a Special Permit by a local entity does not in and of itself determine Siting Board acceptance of the site land use impacts, and that the Siting Board conducts an independent review of the land use impacts.

for this purpose by the Town, and that the Company has received site plan approval from the Agawam Planning Board. Thus, while there may be differences of opinion within the community as to the desirability of locating a generating facility in the Industrial Park, the proposed facility is not clearly inconsistent with the Town's land use objectives for the primary site.

The Siting Board has considered the adequacy of buffering to limit visual and noise impacts of the proposed facility in Sections III.B.2.c. and III.B.2.d., above.[231] Here, we note that, because the proposed facility structures are located near one end of the primary site, much of the on-site buffer extends to the south, with limited on-site buffer in the remaining three directions. However, the site abuts extensive vacant land owned by WMECo, which provides additional buffering in two directions.

With regard to property values, the Siting Board notes that the record does not provide a sufficient basis to conclude either that the proposed facility would have an adverse effect on property values, or that property values would remain stable or rise if the proposed facility were built at the primary site. Given anticipated facility noise impacts, the large scale of the proposed facility relative to existing development, and the expected on-site storage of backup fuel and chemicals, it is possible that construction of the proposed facility at the primary site could adversely affect property values at some nearby parcels. However, since abutting properties are commercial or industrial, any such impacts likely would be limited. In addition, the presence of intervening commercial/industrial properties likely would limit any adverse impact on the property value of nearby residences.

Finally, the Siting Board notes that the Massachusetts DFW has concluded that the design of the proposed facility appears to avoid impacts to box turtles and their habitat at the primary site. In addition, the record demonstrates that a number of authorities, including the NHESP, have concluded that deciduous forest is the preferred habitat of the box turtle, and that such habitat will be available to box turtles at the primary site. The record also shows that the

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[231] The Siting Board further addresses noise impacts in Section III.B.4, below.

area of deciduous forest at the primary site will be preserved, and that installing a fence according to DFW specifications will keep box turtles from entering areas of construction and, later, the proposed facility operations. The record also demonstrates that, despite some disagreement among authorities on the subject, the majority estimate that box turtles range a relatively small distance from home. Thus, the Siting Board concludes that construction and operation of the proposed facility at the primary site will not interfere with normal behavior of the box turtle in its natural habitat, assuming installation of appropriate fencing before the beginning of construction. The Siting Board anticipates that the Company will adhere to the recommendations of the DFW with respect to fencing to protect box turtles at the primary site.

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

The record indicates that existing land uses surrounding the alternative site include a substantial amount of undeveloped land, as well as the sand and gravel operation. As with the primary site, the alternative site is located in an industrially zoned area; however, with the exception of the sand and gravel operation, the only industrial development in proximity to the site is limited light industrial. Since the site is 200 acres in size, a significant buffer can be provided in most directions between the proposed facility and surrounding land uses.

With respect to the utility interconnections, the alternative site would require an electric interconnect of 4.5 miles. The Siting Board notes that, given its length and the inclusion of the off-site overland segment, the electric interconnect may result in significant land use impacts. However, the land use impacts would be somewhat mitigated by the construction of 3.5 miles of the transmission line underground in a former railroad ROW.

BPD has asserted that the land use impacts of the proposed facility at the primary and the alternative sites are comparable. The Siting Board notes that the primary site offers the advantage of shorter utility easements, while the alternative site offers the advantage of a significant natural buffer. The land use impacts arising from the electric interconnect at the alternative site can be minimized using construction techniques and locating the line primarily in an existing ROW. However, while a man-made buffer such as landscaping or a berm can often minimize land use impacts to some degree, the land use impacts at the primary site cannot be minimized to the same extent as at the alternative site, which has the advantage of significant physical distance from the surrounding community. The Siting Board notes that the distance from the nearest residence to the proposed facility is similar at the primary and alternative sites, although the residential density in the area of the alternative site is less than the primary site.

Accordingly, the Siting Board finds that the alternative site would be slightly preferable to the primary 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 cost. The Siting Board then compares the estimated costs of constructing and operating the proposed facilities at the primary and alternative sites.

The Company provided a confidential construction cost estimate for the proposed facility at the Agawam site based on its initial project design (Exh. BP-1C at 3). The Company stated that this cost estimate includes an estimate of the site specific and current information regarding: (1) construction costs, including EPC, construction interest, and construction management costs; (2) electric transmission line and gas pipeline interconnect costs; (3) a contingency allowance of five percent; (4) site costs; and (5) other costs, including development costs and NOx offset costs (id.). The Company subsequently presented more detailed cost estimates which also were revised to show cost reductions stemming from updating of the pro formas originally submitted by the Company (Exhs. HO-RR-6; HO-V-4R; Tr. 13, at 108-112).

The Company also provided a confidential construction cost estimate for the proposed facility at the alternative site, and identified certain site-specific costs which the Company indicated would be higher at the alternative site than at the primary site (Exh. BP-1C at 4). The Company indicated that the total cost for the proposed facility would be approximately $10.725

million higher at the alternative site than at the primary site, primarily due to the need for two gas compressors which would not be required at Agawam; higher electric transmission line interconnect costs; greater gas pipeline costs; and greater costs for sewer and water supply interconnects (id.; HO-RR-66).

The Company asserted that the cost estimates it submitted for the proposed facilitly at both the primary site and at the alternative site are realistic for a facility of the proposed size and design (Exh. BP-1C at 3, 4). The Company further asserted that its estimates of EPC and interconnection costs reflect current information regarding labor markets, interest rates and equipment supplier prices, and are reasonable given the type of facility proposed (id.). In addition, the Company asserted that its contingency allowance, consistent with allowances for other facilities of this size, would cover for any unforeseen development and environmental mitigation costs, as well as capital cost escalation (id. at 3, 4-5).

BPD also identified the costs of several options to minimize further the environmental impacts associated with the proposed facility including: various water supply options and the use of dry cooling; gas supply arrangements to further minimize air quality impacts; and additional noise mitigation measures.

With respect to water supply options for the proposed facility at the primary site, the Company provided a cost comparison for its preferred option, i.e., the Agawam municipal system, and for two identified alternatives, (1) the Connecticut River option, which would require a new intake and supply line from the river to the proposed site, and (2) the groundwater well option, which would require new wells and supply line(s) to the site (Exh. HO-RR-71(supp.)). The Company submitted information showing that the combined capital costs and present value operating costs, in 1996 dollars, would be $5.01 million for the preferred option, $10.21 to $10.56 million for the Connecticut River option, and $4.57 to $5.07 million for the groundwater well option (id.).

With respect to water supply options for the proposed facility at the alternative site, the Company indicated that it had been unable to obtain cost estimates for all of the water supply options at the Southwick site (Exh. HO-RR-70(supp.)). The Company stated, however, that the cost of drawing water from the City of Springfield, either directly or via the Southwick municipal system, would be the same as at the Agawam site (id.). The Company stated that the cost estimate for a well system at the Agawam site represents a reasonable cost estimate for water supply options relying on wellwater at the alternative site in Southwick (id.).

With respect to the use of dry cooling for the proposed facility at either the Agawam or the Southwick site, the Company estimated that costs in 1995 dollars of a dry cooling tower would exceed those for an evaporative cooling tower by $4.4 million to $5 million for construction, $50,000 to $100,000 for maintenance, and an additional unspecified amount to cover increased operating expenses due to capacity losses (Exhs. HO-C-4).[232] The Company indicated that its estimates were based on a dry cooling tower design that would minimize overall project cost (id.). The estimates submitted by the Company indicated that dry cooling costs would be substantially greater than wet cooling costs, primarily due to incremental costs reflecting capacity and efficiency losses, higher maintenance costs, the additional cost of an air cooled condenser, and additional noise mitigation costs for dry cooling (id.; Exhs. HO-C-7; HO-E-62). In addition, the Company noted that, at the primary site, even its estimated expenditure of more than $1,000,000 for noise impact mitigation might not be enough to ensure that the proposed facility would meet MDEP/EFSB noise criteria (Exh. HO-C-4). See Section III.B.2.d., above.

With respect to identified options for further noise mitigation at the primary site, the Company estimated a cost of $156,000 for extending the noise control barrier presently planned for three sides of the cooling tower to the tower's east side (Exh. HO-E-63). The Company asserted that the additional cost, which would provide noise reductions of 11 dBA and 10 dBA at the northeast and southeast property lines of the primary site, respectively, would not be appropriate due to non-residential land uses in those directions (id.).[233]

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[232] The Company also provided an itemized comparison of capital costs for dry and wet cooling (Exh. HO-C-7).

[233] With respect to options and costs for noise mitigation at the primary and alternative sites, the Company stated that noise mitigation features at the alternative site would be

The Company also provided cost estimates for identified options for further noise mitigation at the nearest residential receptors, but contended that such options would be prohibitively expensive for benefits that would likely be imperceptible to residents (Exh. HO-E-64). The Company stated that it would cost: (1) at least $450,000 to eliminate the cooling tower as a significant noise source, a one dBA reduction; (2) at least $250,000 to install high-attenuation louvers on the ventilation air intake for the turbine building, an additional one dBA reduction; and (3) a minimum of $350,000 to double the size of the extra exhaust duct muffler and enclose the turbine exhaust duct and muffler in a masonry-walled building, an additional one dBA reduction (id.).

The record contains estimates of the overall costs of the proposed facility at the primary and alternative sites, including components of capital and operation costs which are site dependent, 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 $10.725 million for the primary site over the alternative site. The record demonstrates that the cost of constructing and operating the proposed facility at the primary site would be less than that at the alternative site. Accordingly, the Siting Board finds that the primary site is preferable to the alternative site with respect to cost.

4. Conclusions

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comparable to those at the primary site (Exh. BP-1B at 8-53).

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. Conclusions on the Proposed Facility at the Primary Site

The Siting Board has found that, with the implementation of the conditions specified in Sections III.B.2, above, the environmental impacts of the proposed facility at the primary site would be minimized with respect to wastewater and stormwater, construction impacts on wetlands, visual impacts, traffic, safety, EMF, and land use. Further, in Section III.B.3, the Siting Board has found that has BPD 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.

The Siting Board has found that the Company has not established that the environmental impacts of the proposed facility at the primary site would be minimized with respect to air quality, water supply, or noise. In Sections III.B.2.a, b, c and d, above, the Siting Board has identified five project design issues which require the Siting Board to evaluate tradeoffs among various environmental impacts or between environmental impacts and cost. These five issues are: (1) stack height, which requires the Siting Board to balance air quality and visual impacts; (2) level of firm gas transportation, which requires the Siting Board to balance air quality impacts and cost; (3) choice of cooling technologies, which requires the Siting Board to balance water supply impacts, noise impacts, and cost; (4) choice of water supply, which requires the Siting Board to balance water supply impacts, land use impacts, and cost; and (5) additional noise mitigation, which requires the Siting Board to balance noise impacts and cost. Thus, to complete its review, the Siting Board must address each of these issues in order to determine whether air quality impacts, water supply impacts, visual impacts and noise impacts would be minimized, consistent with minimizing cost and other environmental impacts.

The Company has proposed a 125-foot stack which, although less than the GEP stack height, would allow the Company to meet MDEP air quality permit requirements, including an emissions limit of 0.00193 lb/MMBtu for formaldehyde. The Company has also identified the option of using a 167.5-foot GEP stack, which would marginally reduce predicted ambient concentrations of criteria and non-criteria pollutants emitted from the proposed facility, as well as predicted ambient concentrations of air toxics. The Company also has identified visual impacts associated with construction of a 167.5-foot stack for the proposed facility. In Section III.B.2.c.iii, above, the Siting Board found that the visual impacts of the proposed facility would be minimized with a 125-foot stack.

The Company's local air modelling shows that, with either a 167.5 or 125 foot stack, combined background and facility ambient concentrations would be well below ambient standards, and that ambient concentrations emitted by the proposed facility would be below all established SILs. The 167.5 foot stack would have substantially greater visual impacts than a 125 foot stack, and would likely require additional construction and visual screening costs. Therefore, the Siting Board concludes that the marginal air quality benefits associated with a 167.5 GEP stack would not outweigh its additional visual impacts and costs. Accordingly, the Siting Board finds that the construction of the proposed facility with a 125-foot stack would minimize environmental impacts, consistent with the minimization of cost.

With regard to the fuel supply for the proposed project, the Company has proposed to contract for firm gas transportation for 335 days per year, consistent with its request for an air permit that allows it to burn oil for up to 720 hours per year. The Company asserts that it needs the flexibility provided by the air permit to compete economically as a merchant power plant. However, the Company does not anticipate that the proposed facility would use oil for more than 100 hours per year in most years.

The Company has also identified the option of acquiring firm transportation of natural gas for 365 days per year, which likely would reduce the air quality impacts of the proposed project by enhancing the availability of natural gas for the proposed project. However, the Company contends that, while a 365-day firm transportation contract is a theoretical option for minimizing reliance on oil firing, such a contractual guarantee would increase the cost of power from the proposed project by $18.8 million/year, almost one cent/kWH.

Given the magnitude of this financial impact on the proposed project, the Siting Board agrees that the cost of a 365-day firm transportation contract would outweigh the marginal air quality benefits of completely eliminating the need for oil firing. Further, with respect to NOx, the pollutant for which control of emissions is particularly important given the classification of Massachusetts as non-attainment for O_3, the cost of firm transportation would significantly exceed the costs of purchasing additional NOx offsets for limited hours of oil firing. Thus, the record does not establish that a 365 day firm transportation contract is necessary to minimize environmental impacts consistent with the minimization of cost.

In reaching this conclusion, the Siting Board notes BPD's representation that oil-fired operation of the proposed facility would not exceed 100 hours in most years, and concludes that a 335 day firm transportation contract, 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 models based on thirty days of oil firing.[234] The Siting Board expects BPD to limit its use of oil to 100 hours or less in most years, and encourages it to modify its fuel supply arrangements if necessary to ensure that this goal is achieved. Accordingly, the Siting Board finds that the Company's plan to contract for firm gas transportation for 335 days per year would minimize environmental impacts, consistent with minimizing cost.

With respect to cooling technologies, the record demonstrates that overall project costs with dry cooling would be substantially greater than with evaporative cooling. The record also indicates that dry cooling would entail significant additional costs for noise mitigation, and that even with such mitigation, the proposed facility with dry cooling nonetheless may fail to meet MDEP noise requirements. In addition, the record demonstrates that water supply resources are adequate to meet the water supply needs of the proposed facility with evaporative cooling. Accordingly, the Siting Board finds that the use of evaporative cooling would minimize

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[234] In addition, the Siting Board notes that a reduced level of oil-firing also would reduce water and traffic impacts.

environmental impacts consistent with the minimization of costs.

In Section III.B.2.b.iii, above, the Siting Board expressed concern that BPD's reliance on its preferred water supply option would require the consumption of large quantities of potable water, with potential impacts on water resources, and noted that the groundwater well option might avoid such impacts. The record demonstrates that the cost of the groundwater well option is comparable to that of the Company's preferred option, although the preferred option has lower costs in the early years of the project. The record also demonstrates that the groundwater well option would require the construction of multiple wells and interconnects to these wells. The Siting Board therefore concludes that the groundwater well option likely would have greater land use impacts than the preferred option. Further, the recharge area for water resources supplying the preferred option would be greater than for those supplying the groundwater well option. In addition, there is the potential for the groundwater well option to adversely affect other water users or wetlands. Accordingly, the Siting Board finds that the Company's preferred water supply option would minimize environmental impacts consistent with the minimization of costs.

With regard to noise impacts, the Company has identified costs for further mitigation of the noise impacts of the proposed facility. These include costs for three options for reducing noise to the southwest of the facility, at the nearest residential receptor: (1) $450,000 for enclosure of the cooling tower; (2) $250,000 to reduce noise from the turbine building ventilation intake; and (3) $350,000 to enlarge and enclose the exhaust duct muffler. The Company also has indicated that a ground level barrier and an extension of the cooling tower fan deck barrier, which would reduce noise to the east of the facility, would cost $156,000.

The record demonstrates that the noise reductions that could be achieved at the nearest residence through additional noise mitigation are minimal, and that noise impacts at the nearest residence are within MDEP guidelines. The Siting Board therefore concludes that additional mitigation would not result in cost-effective noise reduction benefits to neighbors of the proposed facility. We note that the size and configuration of the site is a significant constraint in addressing noise impacts at the nearest residence, as the assumed location of the dominant noise source for that receptor, the cooling tower, already is located on the opposite, or northeast, edge of the site from the receptor. An expansion of the site and the facility layout toward the northeast, if possible, might have provided a more cost-effective means of reducing noise impacts at the nearest residence. In future cases, where site reconfiguration is a potentially cost-effective means of avoiding or minimizing noise impacts, applicants should include such options in their analysis of measures to adequately minimize such impacts.

BPD argues that the $156,000 cost of extending the cooling tower barriers to the east side of the facility cannot be justified, because the abutting land is not zoned for residential use. The record indicates that undeveloped land extends to the southeast, east and northeast for a half mile or more, and confirms that such land is not zoned for residential use. Further, a large abutting landholding in those directions is owned by WMECo, and currently is traversed by transmission lines located at distances of approximately 800 to 1,200 feet to the east and north of the cooling tower location. The record indicates that daytime increases in L_{90} noise exceeding the MDEP guideline would be limited to within approximately 450 to 750 feet of the facility property line.

However, the record does not indicate the area that would be affected by off-site nighttime noise increases approaching or exceeding the MDEP guideline. Further, the record contains little information on the owners and potential uses of vacant land located south, east and north of the abutting WMECo landholding, and within approximately one-half mile of the site. While this land is industrially zoned, the record demonstrates the potential for uses involving nighttime occupancy with a Special Permit. Therefore, the record neither establishes that nighttime noise increases would be ten dBA or less on the abutting WMECo land and vacant land to the south, east and north, nor establishes that possible nighttime noise increases in excess of ten dBA would be acceptable on such land.

The record indicates that extension of the ground level cooling tower barrier and fan deck to the east side of the cooling tower provides a likely cost-effective way to significantly reduce noise impacts of the proposed facility in that direction. In light of the potential for night-time occupancy of the abutting WMECo land and vacant land to the south, east and north, the

Siting Board finds that the extension of the cooling tower barrier to the east side of the cooling tower, likely would be necessary to minimize environmental impacts consistent with minimizing cost.[235] Consequently, the Siting Board requires BPD either to: (1) extend the ground level and fan deck barriers to the east side of the cooling tower; (2) develop alternative noise mitigation satisfactory to all property owners whose properties would otherwise experience increases in L_{90} noise exceeding MDEP guidelines; or (3) demonstrate, either to the Siting Board or to MDEP, that there would be no increases in L_{90} noise exceeding MDEP guidelines on any parcel where night-time occupancy is reasonably likely, given existing zoning restrictions and physical limitations on the development of those sites.

Accordingly, the Siting Board finds that, with the implementation of this condition, the noise impacts of the proposed facility would be minimized consistent with minimizing cost.

Based on its analysis of the five project design issues identified above, the Siting Board concludes that, with the implementation of the aforementioned condition, the air quality, water supply, visual, and noise impacts of the proposed facility at the primary site would be minimized consistent with the minimization of cost and other environmental impacts.

Therefore, the Siting Board finds that, with the implementation of the above condition 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 Sections III.B.2, above, the Siting Board has found that:

- the primary site would be slightly preferable to the alternative site with respect to air quality;
- on balance, the primary site would be slightly preferable to the alternative site with respect to water-related impacts;
- the alternative site would be preferable to the primary site with respect to visual impacts;

[235] We note that measures to mitigate noise increases on such vacant land also would further mitigate noise increases on portions of the abutting WMECo landholding.

- the primary site would be comparable to the alternative site with respect to noise;
- the primary site would be comparable to the alternative site respect to traffic impacts;
- the primary site would be comparable to the alternative site with respect to safety;
- the primary site would be preferable to the alternative site with respect to EMF impacts; and
- the alternative site would be slightly preferable to the primary site with respect to land use.

Accordingly, on balance, the Siting Board finds that the environmental impacts of the proposed facility at the primary and alternative sites are comparable.

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 to 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, BPD will have 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 BPD has considered a reasonable range of practical facility siting alternatives, and that with implementation of the listed conditions relative to air quality, water-related impacts, visual impacts, noise and traffic, 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 project and ancillary facilities at the primary site will be consistent with providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

In Section II.A.3, above, the Siting Board has found that there is a need in the Commonwealth for 252 MW of additional energy resources from the proposed project for economic efficiency purposes beginning in the year in which economic efficiency benefits begin in the region. Further, 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, although the facility as proposed by BPD would include a lower stack height than the MDEP-recognized GEP height and would result in property line noise impacts in excess of the MDEP ten-dBA guideline. The Siting Board agrees with the Company that exceptions to the above guidelines were reasonable options for the Company to consider based on offsetting environmental or cost considerations, and notes that the record suggests MDEP could consider such exceptions if adequate justification were provided.

In its review and balancing of overall environmental and cost considerations in Section III.B, above, the Siting Board has found that the environmental impacts of the proposed facility at the primary site would be minimized consitent with minimizing cost, with (1) a less-than-GEP stack height, as proposed by BPD, and (2) BPD's compliance with the condition set forth in Section III.B.4 relating to noise impacts. The Siting Board therefore finds that the proposed project is likely to be consistent with various health, environmental protection and resource use and development policies of the Commonwealth which relate to the environmental impacts and cost of the Commonwealth's energy supply.

Accordingly, the Siting Board APPROVES the petition of Berkshire Power Development, Inc. to construct a 252 MW bulk generating facility and ancillary facilities in Agawam, Massachusetts subject to the following conditions.

(A) In order to establish that the project is likely to be constructed on schedule and will be able to perform as expected, the Siting Board requires BPD to provide the it with a copy of a signed EPC turnkey contract between BPD and B&V/ABB Power Generation that is identical or similar in all significant provisions to the Term Sheet.

(B) In order to establish that the proposed project has access to the regional transmission system, the Siting Board requires BPD to provide the Siting Board with a copy of a signed interconnection agreement between BPD and NU.

(C) In order to establish that the project is likely to be operated and maintained in a manner consistent with appropriate performance objectives, the Siting Board requires BPD to provide it with a copy of a signed O&M agreement between BPD and ABB O&M that is identical or similar in all significant provisions to the draft contract.

(D) In order to establish that the proposed project has a fuel acquisition strategy which ensures a low-cost reliable supply of energy, the Siting Board requires BPD to provide it with signed contract(s) for 335 days or more of firm transportation from Wright (or a comparable location) to the proposed facility, or a comparable arrangement, such as firm deliverability based on transportation from Wright combined with downstream supplies.

At such time as the Company provides the Siting Board with the information listed above, the Siting Board shall review the information and determine if the Company has complied with each condition. The Company shall not receive final approval of its project until it complies with these conditions.

In addition, the Company shall comply with the following conditions during construction and operation of the proposed facility:

(E) In order to mitigate CO_2 emissions, the Siting Board requires BPD to provide CO_2 offsets through an annual seedling distribution program or a comparable tree planting or forestation program, or combination thereof, so as to attain an annual offset level equivalent to 0.385 percent of annual facility emissions within five years of facility start-up and 0.550 percent of annual facility emissions within 20 years of facility start-up.

(F) In order to minimize water supply impacts, the Siting Board directs the Company to work in conjunction with the City of Springfield to identify and as appropriate implement measures to ensure the long-term ability of the Springfield municipal system, including Cobble Mountain, to supply BPD and other customers.

(G) In order to minimize visual impacts, the Siting Board directs the Company to provide reasonable off-site shrub and tree plantings to help screen the proposed facility from roadways and properties on or near the intersection of Losito Road and Shoemaker Lane, and on or near Suffield Street and the southern portion of Shoemaker Lane, and at other locations within one mile of the proposed facility, as may be requested by property owners or appropriate municipal officials; consistent with the directives set forth in Section III.B.2.c.iii, above.

(H) In order to minimize traffic impacts, the Siting Board requires BPD, in consultation with the Town of Agawam, to develop and implement a traffic mitigation plan which includes scheduling to avoid peak travel periods, route modification, or other appropriate measures to minimize construction-related traffic impacts at the Suffield Street/Shoemaker Street intersection during actual intersection peak periods.

(I) In order to alleviate public concern, the Siting Board directs the Company, to monitor fogging and icing in the vicinity of the proposed facility, and as necessary, establish a plan in cooperation with local officials, to alert motorists and residents concerning any project-related fogging or icing episodes affecting public safety.

(J) In order to minimize noise impacts consistent with minimizing cost, the Siting Board requires BPD either to: (1) extend the cooling tower and fan deck barriers to the east side of the cooling tower; (2) develop alternative noise mitigation satisfactory to all property owners whose properties would otherwise experience increases in L_{90} noise exceeding MDEP guidelines, or (3) demonstrate, either to the Siting Board or to MDEP, that there would be no increases in L_{90} noise exceeding MDEP guidelines on any parcel where night-time occupancy is reasonably likely, given physical and zoning restrictions.

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 CONDITIONAL APPROVAL.

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 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 19th day of June, 1996

[TABLE 1: RANGE OF REGIONAL NEED CASES - SUMMER (COMPANY ANALYSIS) 1999-2001]

[TABLE 2: RANGE OF REGIONAL NEED CASES - WINTER (COMPANY ANALYSIS 1998/1999 - 2000/2001]

[TABLE 3: RANGE OF REGIONAL NEED CASES - SUMMER (STAFF ANALYSIS) 1999-2001]

[TABLE 4: RANGE OF REGIONAL NEED CASES - WINTER (STAFF ANALYSIS) 1998/1999 - 2000/2001]

[TABLE 5: RANGE OF MASSACHUSETTS NEED CASES - SUMMER (COMPANY ANALYSIS) 1999]

[TABLE 6: RANGE OF MASSACHUSETTS NEED CASES - WINTER (COMPANY ANALYSIS) 1999]

[TABLE 7: RANGE OF MASSACHUSETTS NEED CASES - <u>SUMMER</u> (STAFF ANALYSIS) 1999]

[TABLE 8: RANGE OF MASSACHUSETTS NEED CASES - <u>WINTER</u> (STAFF ANALYSIS) 1998/1999 - 2000/2001]

[TABLE 9: EMISSIONS SAVINGS WITH DISPATCH OF PROPOSED PROJECT (TONS)]

[TABLE 10: ALTERNATIVE TECHNOLOGIES - POLLUTANT EMISSIONS]

[TABLE 11: TECHNOLOGY PARAMETERS AND LEVELIZED COSTS]

[EXHIBIT A: SITE LOCATION - AGAWAM]

[EXHIBIT B: SITE LOCATION - SOUTHWICK]

[EXHIBIT C: FACILITY LOCATION - AGAWAM]

Unanimously APPROVED by the Energy Facilities Siting Board at its meeting of June 19, 1996 by the members an designees present and voting. Voting for approval of the Tentative Decision as amended: John B. Howe (Chairman, EFSB/DPU); Janet Gail Besser (Commissioner, DPU); David O'Conner (for David A. Tibbetts, Secretary of Economic Affairs; Alan Bedwell (for Trudy Coxe, Secretary of Environmental Affairs); and Joseph Faherty (Public Member).

John B. Howe
Chairman

Dated this 19th day of June, 1996

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).