COMMONWEALTH OF MASSACHUSETTS

Energy Facilities Siting Board

)

In the Matter of the Petition of)

ANP Bellingham Energy Company) EFSB 97-1

for Approval to Construct)

a Bulk Generation Facility and Ancillary Facilities)

in Bellingham, Massachusetts)

)

FINAL DECISION

M. Kathryn Sedor

Hearing Officer

August 18, 1998

On the Decision:

Jeffrey Brandt

William S. Febiger

Enid Kumin

Peter Mills

APPEARANCES: Edward L. Selgrade, Esq.

Law Offices of Edward L. Selgrade, Esq.

200 Wheeler Road, 4th Floor

Burlington, Massachusetts 01803

FOR: ANP Bellingham Energy Company

<u>Petitioner</u>

Clifford A. Matthews

Chairman

Bellingham Conservation Commission

P.O. Box 213

Bellingham, Massachusetts 02019

FOR: Bellingham Conservation Commission

<u>Intervenor</u>

Mark J. Lanza

Town Attorney

150 Emmons Street

Franklin, Massachusetts 02038

FOR: Town of Franklin

Intervenor

J. Raymond Miyares, Esq.

Pickett and Miyares

47 Winter Street, 7th Floor

Boston, Massachusetts 02108

FOR: Town of Franklin

Intervenor

Kathryn Reid, Esq.

New England Power Company

Massachusetts Electric Company

25 Research Drive

Westborough, Massachusetts 01582

FOR: New England Power Company

- and-

Massachusetts Electric Company

Intervenor

Kenneth and Judith Barnett

123 Maple Street

Bellingham, Massachusetts 02019

Intervenor

Linda L. Blais

155 Maple Street

Bellingham, Massachusetts 02019

<u>Intervenor</u>

Frank E. Falvey

920 Pond Street

Franklin, Massachusetts 02038

<u>Intervenor</u>

Joseph A. Goulart

9 Sunken Meadow Road

Franklin, Massachusetts 02038

<u>Intervenor</u>

James P. LaPlante

91 Chestnut Street

Franklin, Massachusetts 02038

<u>Intervenor</u>

Gary B. McAlister

35 Stanwood Drive

Franklin, Massachusetts 02038

<u>Intervenor</u>

John DeTore, Esq.

Rubin & Rudman

50 Rowes Wharf

Boston, Massachusetts 02110

FOR: Infrastructure Development Corporation

Interested Person

Mark A. Brady

11 Sunken Meadow Road

Franklin, Massachusetts 02038

Interested Person

Peter and Trisha Dorfman

23 Oxford Drive

Franklin, Massachusetts 02038

Interested Person

Frances Fabricotti

106 Mendon Street

Bellingham, Massachusetts 02019

Interested Person

Jon Fish

19 Stonehedge Road

Bellingham, Massachusetts 02019

Interested Person

Susan M. Flaherty

10 Sunken Meadow Road

Franklin, Massachusetts 02038

Interested Person

Richard R. Cornetta, Jr., Esq.

12 Washington Street

Franklin, Massachusetts 02038

<u>Interested Person</u>

John D. and Judith T. Webb

3 Sunken Meadow Road

Franklin, Massachusetts 02038

<u>Interested Person</u>

Richard G. McLaughry, Esq.

Robert A. Nailing, Esq.

Cabot Power Corporation

75 State Street, 12th Floor

Boston, Massachusetts 02109

FOR: Cabot Power Corporation

<u>Interested Person</u>

Marc A. Silver, Esq.

Sherburne, Powers & Needham

One Beacon Street

Boston, Massachusetts 02108

FOR: Ocean State Power

<u>Interested Person</u>

Mary Beth Gentleman, Esq.

Andrew Latimer, Esq.

Foley, Hoag & Eliot LLP

One Post Office Square

Boston, Massachusetts 02019

FOR: U.S. Generating Company

Interested Person

TABLE OF CONTENTS

LIST OF ABBREVIATIONS

Abbreviation Explanation

AALs Annual allowable ambient limits

ABB Asea Brown Boveri, Inc.

ACS Advanced Cycle System

AFB Atmospheric fluidized bed coal technology

AGT Algonquin Gas Transmission Company

Algonquin Algonquin Gas Transmission Company

ANP ANP Bellingham Energy Company

ANP Bellingham ANP Bellingham Energy Company

BACT Best available control technology

BCC Bellingham Conservation Commission

bmt Billion metric tons

BECo Boston Edison Company

Btu/kwh British thermal units per kilowatt hour

CAAA Federal Clean Air Act Amendments of 1990

Cabot Cabot Power Corporation

CC Combined Cycle

CCWCs Circulating cooling water coolers

CELT Capacity, Energy, Loads and Transmission (yearly reports prepared by NEPOOL)

CEMs EPA's Continuous Emissions Monitoring System

CG Integrated Coal Gasification

City of New Bedford City of New Bedford v. Energy Facilities Siting Council, 413 Mass. 482 (1992)

CO Carbon monoxide

CO_2 Carbon dioxide

Company ANP Bellingham Energy Company

CT Generation Combustion Turbine

CRWA Charles River Watershed Association

dBA A-weighted Decibel

DCR Debt coverage ratios

DEIR Draft Environmental Impact Report

Department Department of Telecommunications and Energy

DOE The United States Department of Energy

DOT The United States Department of Transportation

$/kWh Dollars per kilowatt-hour

DSM Demand side management

EMF Electric and magnetic fields

ENF Environmental Notification Form

EPA The United States Environmental Protection Agency

EPC Engineering, procurement, and construction

EPRI Electric Power Research Institute

ERCs Emission reduction credits

ERP Emergency Response Plan

FEIR Final Environmental Impact Report

FERC Federal Energy Regulatory Commission

Firm gas supply The assumption used in analyzing fuel costs that gas supply from the wellhead to the proposed facility will be firm

Franklin Town of Franklin

Franklin Initial Brief Town of Franklin Initial Brief

Franklin Reply Brief Town of Franklin Reply Brief

GCC Gas-fired combined cycle unit

GEP Good Engineering Practice

GIS Geographic Information Systems Mapping

gpd Gallons per day

GTF NEPOOL Generation Task Force

HRSG Heat recovery steam generator

IDC Infrastructure Development Corporation

IDLH Immediately Dangerous to Life or Health

IPP Independent power producer

IRR Internal Rate of Return

kV Kilovolt

L_{90} The level of noise that is exceeded 90 percent of the time

LAER Lowest Achievable Emission Rate

lbs/MMBtu Pounds per million British thermal units

L_{dn} EPA's day-night noise level

L_{eq} 24-hour equivalent noise level

LOS Level of service -- a measure of the efficiency of traffic operations at a given location

MAAQS Massachusetts ambient air quality standards

MA DEM Massachusetts Department of Environmental Management

MassGIS Massachusetts Geographic Information System

MA WMA Massachusetts Water Management Act

MCZM Massachusetts Coastal Zone Management

MDEP Massachusetts Department of Environmental Protection

MECo Massachusetts Electric Company

mG Milligauss

mgy Million gallons per year

MHC Massachusetts Historical Commission

MHD Massachusetts Highway Department

MW Megawatt

NAAQS National ambient air quality standards

NEA Northeast Energy Associates

NEPCO New England Power Company

NEPOOL New England Power Pool

NHESP Natural Heritage and Endangered Species Program

NMLs Noise Monitoring Locations

NOx Nitrogen oxides

NPDES National Pollutant Discharge Elimination System

NP National Power

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

OSP Ocean State Power

PAL Public Archaeology Laboratory, Inc.

Pb Lead

PC Pulverized coal facility

PFB Pressurized fluidized bed coal facility

PM-10 Particulates

PPAs Power purchase agreements

PSD Prevention of significant deterioration

PURPA Public Utility Regulatory Policies Act of 1978, 16 U.S.C. §§ 796, 824a-3

QF Qualifying facility

RAA NEPOOL 1996 Resource Adequacy Assessment

RFP Request for Proposals

ROW Right-of-way

SACTI Seasonal/Annual Cooling Tower Plume Impact model

SCR Selective Catalytic Reduction System

SILs Significant impact levels

Siting Board Energy Facilities Siting Board

Siting Council Energy Facilities Siting Council

SO_2 Sulfur dioxide

SOx Sulfur oxides

SPCCP Spill Prevention, Control and Countermeasure Plan

SS-RFP Site Selection RFP

TAG EPRI Technical Assessment Guide

TELs Threshold effects exposure limits

TGP Tennessee Gas Pipeline Company

Town Town of Bellingham

tpy Tons per year

USGen U.S. Generating Company

USGS United States Geological Survey

USGS Study 1991 Report by USGS, Water Resources and Aquifer Yields in Charles River Basin, Massachusetts

VOCs Volatile organic compounds

ZBA Zoning Board of Appeals

The Energy Facilities Siting Board ("Siting Board") hereby APPROVES subject to conditions the petition of ANP Bellingham Energy Company to construct a net nominal 580-megawatt bulk generating facility and ancillary facilities at the proposed site in Bellingham, Massachusetts.

I. INTRODUCTION

A. Summary of the Proposed Project and Facilities

ANP Bellingham Energy Company ("ANP Bellingham" or "Company") has proposed to construct a natural gas-fired, combined-cycle, electric generating facility with a nominal net electrical output of 580 megawatts ("MW") in the Town of Bellingham, Massachusetts ("project") (Exh. BEL-1, at 1-5). The proposed project would be located on an approximately 20-acre footprint located within an approximately 125-acre parcel of undeveloped land (id.). The Company has proposed that natural gas would be delivered to the project via a new, 14-inch, 1.1-mile pipeline to be constructed by Algonquin Gas Transmission Company ("Algonquin" or "AGT"), which would extend from Algonquin's existing pipeline facility in Bellingham to the project site (id. at 1-6 to 1-7). Electric power generated by the proposed project would be supplied for transmission through interconnection to an existing 345 kilovolt ("kV") New England Power Company ("NEPCo") transmission line which traverses the proposed site (id. at 1-7).

In addition to its natural gas and electrical interconnections, the proposed project includes the following major components and structures: two single shaft power islands, each of which consists of an Asea Brown Boveri ("ABB") GT-24 combustion turbine, a heat recovery steam generator ("HRSG"), a steam turbine and an electric generator, a dry low nitrogen oxides ("NOx") combustion system and a selective catalytic reduction ("SCR") system for control of nitrogen oxides; two dry condenser cooling towers; and two 180-foot exhaust stacks. Additional project components include a 1.5-million-gallon demineralized water storage tank, a 1.0-million-gallon raw water storage tank, and two 14,000-gallon ammonia storage tanks.

The project is designed with the capacity to operate at its standard baseload level, and to augment its electricity production through steam injection to meet higher demand levels

(id. at 1-6). Each of the project's two combustion turbines will generate approximately

180 MW of electricity (210 MW with steam augmentation), and the exhaust heat of the turbine will be recaptured to produce steam and drive the steam turbine, producing an additional 95 MW of electricity (85 MW with steam augmentation) (id.).

The Company's proposed site for the project is located in an industrially zoned area in Bellingham (id. at 1-8). The site is predominantly wooded, and is presently undeveloped (id.). Maple Street in Bellingham, which is primarily residential in nature, borders the site to the east and south (id.). Route 495 borders the site to the west (id. 1-13). Property controlled by the U.S. Army Corps of Engineers along the Charles River forms the site's northern boundary (id.).

ANP is an affiliate of American National Power, Inc. and was formed in April 1997 for the development of the proposed project (id. at 1). American National Power is an affiliate of National Power, plc, ("NP") which is the leading electric power generating company in the United Kingdom and owns and/or operates approximately 24,100 MW of generating capacity world-wide with 7,400 MWs located in eight countries outside the United Kingdom including the United States (id.).

B. Jurisdiction

The Company’s petition to construct a bulk generation facility was filed in accordance

with G.L. c. 164, § 69H, which requires the Siting Board to implement the energy policies

in its statute to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost, and pursuant to G.L. c. 164, § 69J,

which requires electric companies to obtain Siting Board approval for construction of

proposed facilities at a proposed site before a construction permit may be issued by another

state agency.

As a wholesale electric generator with a design capacity of approximately 580 MW,

the Company's proposed generating unit falls squarely within the first definition of "facility"

set forth in G.L. c. 164, § 69G. That section states, in part, that a facility is:

(1) any bulk generating unit, including associated buildings and

structures, designed for, or capable of operating at a gross

capacity of one hundred megawatts or more.

At the same time, the Company's proposal to construct an electric interconnection, a

gas interconnection and other structures at the site fall within the third definition of "facility"

set forth in G.L. c. 164, § 69G, which states that a facility is:

(3) any ancillary structure including fuel storage facilities which is

an integrated part of the operation of any electric generating unit

or transmission line which is a facility.

C. <u>Procedural History</u>

On May 27, 1997, the Company filed with the Siting Board a petition to construct and operate a nominal net 580-megawatt natural gas-fired, combined-cycle power plant and ancillary facilities in Bellingham, Massachusetts. The Siting Board docketed the petition as EFSB 97-1. On July 10, 1997, the Siting Board conducted a public hearing in Bellingham and on August 14, 1997, the Siting Board conducted a public hearing in Franklin, Massachusetts. In accordance with the direction of the Hearing Officer, the Company provided notice of the public hearing and adjudication.

Timely petitions to intervene were filed by: Kenneth and Judith Barnett; the Town of Bellingham Conservation Commission; ("Bellingham Conservation Commission");

Linda L. Blais; Trisha and Peter Dorfman; Henry E. Faenza; Frank E. Falvey; Jon Fish; Susan M. Flaherty; the Town of Franklin ("Franklin"); Paul F. Gibbs; Joseph A. Goulart; James P. LaPlante; Gary B. McAlister; Northeast Energy Associates ("NEA"); New England Power Company and Massachusetts Electric Company ("NEPCo/MECo"); Ocean State Power ("OSP"); Ross P. Thayer; Judith T. and John D. Webb, Jr.; and Mary Jo Yasatovich. Timely petitions to participate in the proceeding as an Interested Person were filed by: Cabot Power Corporation ("Cabot"); Frances Fabricotti; and U.S. Generating Company ("USGen"). In addition, the Siting Board received late filed petitions to intervene from: Mark A. Brady on September 25, 1997; the Wrentham Research Group ("WRG") on October 2, 1997; Robert B. Lovett on October 9, 1997; and Infrastructure Development Corporation ("IDC") on November 10, 1997. ANP filed an opposition to the petitions of IDC, NEA and OSP, and filed a motion to impose certain conditions on those persons granted status to intervene and participate in this proceeding. USGen and NEA filed a response to ANP's motion for conditions.

The Hearing Officer allowed the Bellingham Conservation Commission, the Town of Franklin and NEPCo/MECo to participate as full parties (Hearing Officer Procedural Order, September 24, 1997). Frank Falvey and Paul Gibbs were granted limited intervention status with respect to environmental and associated cost issues, and issues concerning need. In addition, Kenneth and Judith Barnett, Linda Blais, Joseph A. Goulart, James P. LaPlante, Gary B. McAlister, and Mary Jo Yasatovich were granted status as limited intervenors with respect to environmental and associated cost issues (id.). NEA was granted status as a limited intervenor with respect to water withdrawal issues and was granted status as an interested person relative to the other issues in this case (id.). Status as an interested person was granted to OSP, Trisha and Peter Dorfman, Henry Faenza, Jon Fish, Susan Flaherty, and John and Judith Webb, Cabot, Frances Fabricotti and USGen (id.). The Hearing Officer also denied ANP's motion for conditions (Hearing Officer Procedural Order, September 24, 1997). Further, the Hearing Officer denied the late-filed petitions of Robert B. Lovett, Ross P. Thayer and WRG (Hearing Officer Procedural Orders, September 24, 1997, October 16, 1997, and November 4, 1997). The Hearing Officer also denied Mr. Brady's and IDC's petitions to intervene, but allowed Mr. Brady and IDC to participate as interested persons (Hearing Officer Procedural Order, December 16, 1997).

On September 23, 1997, the Company filed a motion requesting that it be permitted to withdraw its alternative site from consideration by the Siting Board in this proceeding. On December 16, 1997, this motion was granted (see section I.D, below).

The Siting Board conducted sixteen days of evidentiary hearings commencing on

January 28, 1998 and ending on March 31, 1998. The Company presented the testimony of thirteen witnesses: Daniel Peaco of LaCapra Associates, who testified as to the need for the proposed project; Douglas Smith of LaCapra Associates, who testified as to alternative technologies; Robert Charlebois, project director for ANP, who testified as to viability, site selection, water, carbon dioxide ("CO_2") mitigation and other issues; Steven Pedrick, construction manager for the proposed project, who testified as to design issues, operation, maintenance, visual, traffic and safety issues; Robert Haupt, vice president of the Company, who testified as to viability, cost and steam augmentation issues; Daniel Lorden, project director of ANP, who testified on interconnection issues; Robert Kasle, manager of fuel procurement for the Company, and Geoffrey Mitchell of Merrimack Energy, who jointly testified as to the project's fuel acquisition strategy; Frederick M. Sellers, vice president of Earth Tech, who testified as to site selection, air, and visual issues; David Keast, an independent acoustical engineer, who testified as to noise impact and noise mitigation issues; Lynn Gresock, project manager for Earth Tech, who testified as to traffic, visual, wetlands and other environmental issues; Dr. William H. Bailey, President of Bailey Research Associates, Inc., who testified as to electric and magnetic field issues ("EMF"); and Richard Friend, hydrogeologist for Earth Tech, who testified on water supply and resource issues.

Intervenor Goulart presented the testimony of two witnesses: Interested Person Mark A. Brady, and Patricia LoTurco, a member of the Wrentham Research Group.

On April 17, 1998, Mark Brady filed two motions to re-open the record. The motions were subsequently denied by the Hearing Officer.

The Hearing Officer entered more than 1000 exhibits into the record consisting primarily of information and record request responses. The Company entered more than 80 exhibits into the record; the Bellingham Conservation Commission submitted more than 100 exhibits into the record; the Town of Franklin entered more than 62 exhibits into the record; NEA submitted more than 20 exhibits into the record; and Mr. Goulart entered more than 20 exhibits into the record. On April 21, 1998, initial briefs were filed by the Company, the Bellingham Conservation Commission and the Town of Franklin. Also on that date, a joint initial brief was filed by Joseph Goulart and Mark Brady. On April 27, 1997, reply briefs were filed by the Company and the Town of Franklin.

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 as follows. First, the Siting Board requires the applicant to show that additional energy resources are needed. U.S. Generating Company, EFSB 96-4, at 6 (1997) ("Millennium Power Decision"); Dighton Power Associates, EFSB 96-3, at 5 (1997) ("Dighton Power Decision"); Northeast Energy Associates, 16 DOMSC 335, 343 (1987) ("NEA Decision") (see Section II.A, below). Second, the Siting Board requires the applicant to show that, on balance, its proposed project is superior to alternative approaches in the ability to address the previously identified need and in terms of cost, environmental impact, and reliability. Millennium Power Decision, EFSB 97-4, at 6; Dighton Power Decision, EFSB 96-3, at 5; 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. Millennium Power Decision,

EFSB 97-4, at 6-7; Dighton Power Decision, EFSB 96-3, at 6; 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, where an alternate 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. Millennium Power Decision,

EFSB 96-4 at 7; Dighton Power Decision, EFSB 96-3, at 6; NEA Decision,

16 DOMSC at 343 (see Section III.A, below).

In cases where no alternative site is noticed, the applicant must demonstrate that its proposed facilities' siting plans are superior to alternatives, and that its proposed facility is sited at a location that minimizes costs and environmental impacts while ensuring supply reliability. Specifically, the applicant must show (a) that it has examined a reasonable range of practical facility siting alternatives by meeting a two-pronged test: it must establish that it (1) 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, and (2) identified at least two potential facility sites with some measure of geographic diversity; (b) that its proposed facility is sited, designed and mitigated in a manner that will minimize cost and environmental impacts; and (c) that an appropriate balance will be achieved among conflicting environmental concerns as well as among environmental impacts, cost and reliability (see Section III.B, below).

In the present case, the Siting Board allowed ANP to withdraw its noticed alternative site. Consequently, we apply the standard of review applicable to those cases where the applicant has not noticed an alternative site for its proposed project.

II. ANALYSIS OF THE PROPOSED PROJECT

A. Need Analysis

1. Standard of Review

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

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

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

With respect to the issue of regional need versus Massachusetts need, the Siting Board noted the integration of the Massachusetts electricity system with the regional electricity system and the resulting link between Massachusetts and regional reliability (id. at 422). The Siting Board noted the inherent reliability and economic benefits which flow to Massachusetts as a result of this integration (id.). Thus, the Siting Board concluded that consideration of regional need must be a central part of any need analysis for a power generation project not linked to individual utilities by power purchase agreements ("PPAs") (id. at 416). The Siting Board also noted that the Massachusetts Legislature clearly foresaw the need for "cooperation and joint participation in developing and implementing a regional bulk power supply of electricity" when it enacted G.L. c. 164A and in this same enactment acknowledged that power generating facilities would provide electric power across state lines. G.L. c. 164A, §§ 3, 4. Accordingly, the Siting Board found that an analysis of regional need must serve as a foundation for an analysis of Massachusetts need. EEC (remand) Decision,

1 DOMSB at 417.

In evaluating the need for new energy resources to meet reliability objectives, the Siting Board may evaluate the reliability of supply systems in the event of changes in demand or supply, or in the event of certain contingencies. With respect to changes in demand or supply, the Siting Board has found that new capacity is needed where projected future capacity available to a system is found to be inadequate to satisfy projected load and reserve requirements. Millennium Power Decision, EFSB 96-4, at 9; Dighton Power Decision, EFSB 96-3, at 8; 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. Millennium Power Decision, EFSB 96-4, at 9; Dighton Power Decision, EFSB 96-3, at 8; 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. Millennium Decision, EFSB 96-4, at 9; Dighton Power Decision, EFSB 96-3, at 9; EEC (remand) Decision, 1 DOMSB at 422. With respect to the issue of establishing need on economic efficiency or environmental grounds, the Siting Board notes that such analyses of need would be consistent with its statutory obligation to ensure a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. G.L. c. 164, §§ 69H, 69J. Millennium Power Decision, EFSB 96-4, at 10; Dighton Power Decision, EFSB 96-3, at 8-9; 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, but also the consideration of whether proposals to construct energy facilities within the Commonwealth are needed to meet New England's energy needs. Millennium Decision, EFSB 96-4, at 10; Dighton Power Decision, EFSB 96-3, at 8-9; 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. Millennium Power Decision, EFSB 96-4, at 10; Dighton Power Decision, EFSB 96-3, at 9; EEC (remand) Decision, 1 DOMSB at 417-418. However, in response to the Court's reminder in City of New Bedford that its statutory mandate is limited to ensuring that a necessary energy supply is provided for the Commonwealth, the Siting Board found in the EEC (remand) Decision that reliability, economic, or environmental benefits associated with the additional energy resources from a proposed project must directly relate to the energy supply of the Commonwealth for them to be considered in support of a finding of Massachusetts need.

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

2 DOMSB at 26.

In its first review of a petition by a non-utility generator ("NUG") to construct a jurisdictional facility, the Siting Board found that, consistent with current energy policies of the Commonwealth, Massachusetts benefits economically from the addition of cost-effective qualifying facility ("QF") 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.

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. Millennium Power Decision, EFSB 96-4, at 12; Dighton Power Decision, EFSB 96-3, at 9-10; West Lynn Cogeneration, 22 DOMSC 1,

9-47 (1991) ("West Lynn Decision"). Therefore, consistent with the Siting Board's precedent and reflecting the directives of the Court in City of New Bedford, Point of Pines, and Attorney General, the Siting Board here reviews the need for the proposed project for reliability, economic and environmental purposes.

2. Reliability Need

The Siting Board has found that it is appropriate to consider the need for capacity beyond the first year of proposed facility operation as part of assessing need for reliability purposes in reviews of NUG projects. See Millennium Power Decision, EFSB 96-4, at 12; Dighton Power Decision, EFSB 96-3, at 10; 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 consider explicitly need for the proposed facility during the 2000 to 2006 time period.

a. New England

ANP asserted that there is a need for at least 580 MW of additional energy resources in New England beginning in the year 2000 and beyond (Exh. BEL-1, at 2-21). In support, the Company presented a series of forecasts of demand and supply for the region based primarily on the 1997 forecasts and other data published by NEPOOL (id. at 2-5; Exh. HO-RR-12). The Company indicated that it compared its demand and supply forecasts to produce a series of need forecasts (Exh. BEL-1, at 2-20 to 2-21).

The Company stated that the forecasts of summer demand and supply are developed from individual forecasts of several underlying factors which include: (1) unadjusted peak loads; (2) utility-sponsored demand side management ("DSM") resources available on peak; (3) NUG netted from load; (4) supply resources; and (5) required reserve margin (id. at 2-3). The Company stated that it developed "adjusted" summer peak load by subtracting the DSM and NUG factors from the unadjusted peak load; the adjusted peak load then was multiplied by a factor reflecting the required reserve margin to yield a forecast of total capacity requirements (id. at 2-9). The Company stated that projected supply resources were then subtracted from the total capacity requirements in each year of the forecast to provide a forecast of the magnitude and need for new energy resources (id. at 2-20).

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

(1) Demand Forecasts

(a) Description

ANP presented forecasts of unadjusted summer peak load and DSM savings derived from information contained in the 1996 and 1997 Capacity, Energy, Loads and Transmission ("CELT") reports published by NEPOOL (Exhs. HO-N-2, at 1; HO-RR-13).

To develop forecasts of adjusted load, the Company combined each of these peak load forecasts with (1) the 1997 CELT report forecast of NUG netted from load, and (2) one of three forecasts of DSM savings based on the 1997 CELT report forecast of DSM savings (Exhs. BEL-1, at 2-8 to 2-9 and app. D; HO-RR-13).

i) Demand Forecast Methods

The Company presented a base case unadjusted peak load forecast, derived directly from the 1997 NEPOOL CELT report reference forecasts of unadjusted load for summer peak ("1997 CELT forecast") (Exh. HO-RR-13). The Company stated that NEPOOL uses an econometric model based on a number of New England economic variables to forecast trends in the economy and resulting levels of energy consumption and peak demand (Tr. 1, at 17). The Company asserted that the reference forecast provides a reasonable projection of regional demand (id.). The Company also presented the 1996 CELT report high case ("CELT high case") and low case ("CELT low case") demand forecasts, which are based on optimistic and pessimistic economic forecasts, respectively, to illustrate the full range of uncertainty in the peak load (Exhs. BEL-1, at 2-8 to 2-9 and app. D; Tr. 1, at 18-19).

ii) DSM

The Company provided three forecasts of DSM: (1) a base DSM scenario, which is the current forecast of company-sponsored DSM savings used in NEPOOL's 1996 CELT report; (2) a high DSM scenario which is 110 percent of the base scenario; and (3) a low DSM scenario, which is 90 percent of the base DSM scenario (Exh. BEL-1, at 2-9). The Company stated that, historically, NEPOOL has overestimated DSM savings but that more recent NEPOOL forecasts have been lower and closer to actual savings (id.).

iii) Adjusted Load Forecasts

The Company stated that to develop forecasts of adjusted load, the 1997 CELT unadjusted summer base case load forecast was combined with the (1) the 1997 CELT report forecast of NUG netted from load, and (2) three forecasts of DSM savings (Exh. HO-N-4.2). In addition, the 1996 CELT unadjusted summer high and low case forecasts were each combined with (1) the 1997 CELT forecast of NUG netted from load, and (2) the base DSM scenarios (Exhs. HO-N-1, at 2; HO-N-2, at 2; BEL-1, at app, D). Thus, the Company presented five forecasts of adjusted summer peak load.

(b) Analysis

The Siting Board previously has acknowledged that the CELT report generally can provide an appropriate starting point for resource planning in New England, and has accepted the use of CELT forecasts for the purposes of evaluating regional need in previous reviews of proposed NUG facilities. Millennium Power Decision, EFSB 96-4, at 16; Berkshire Power Decision, 4 DOMSB at 272; NEA Decision, 16 DOMSC at 354. In addition, the Siting Board has relied primarily on the more recent available forecasts in its analysis of need. See Berkshire Power Decision, 4 DOMSB at 257.

Here, the Company derived an unadjusted base case summer demand forecast and base case DSM scenario directly from the 1997 CELT forecast, which is the most recent CELT forecast. The Company derived two additional DSM scenarios from the base DSM scenario. The Company adjusted the unadjusted base case forecast by base, high and low DSM scenarios, for a total of three adjusted forecasts.

In addition, the Company provided the CELT high case demand forecast and CELT low case demand forecast as extreme demand forecasts, in order to test the sensitivity of the results of analysis of the base case forecast. As noted above, NEPOOL assigns a low probability of occurrence to each of these forecasts. Consistent with previous Siting Board decisions (see, e.g., Millennium Power Decision, EFSB 96-4, at 17; Cabot Decision,

2 DOMSC at 274), the Siting Board finds that these forecasts represent a sensitivity analysis of varying economic assumptions rather than forecasts of regional demand.

Overall, the Company has presented one base case forecast adjusted by three forecasts of DSM. Given uncertainties in forecasting demand, the Siting Board has previously found that it is reasonable to include a range of forecasts in a company's reliability need analysis. See, e.g., Millennium Power Decision, EFSB 96-4, at 17; Berkshire Power Decision,

4 DOMSB at 261, n.23. However, as noted above, the Siting Board has acknowledged the value of the CELT report for regional resource planning and has accepted the use of CELT forecasts for the purpose of evaluating regional need. In addition, in reviewing need forecasts, the Siting Board has placed more weight on the base case forecast. Berkshire Power Decision, 4 DOMSB at 274. Here, the Company has provided the most recent CELT forecast as a base case forecast and also has provided high and low forecasts for the purpose of demonstrating the range of potential demand. Therefore, the Siting Board finds that it is reasonable, for purposes of this review, to rely on one base case forecast for summer peak load.

Accordingly, the Siting Board finds that the 1997 CELT forecast is an appropriate base case summer peak load forecast for use in the analysis of regional need for the years 2000 and beyond.

The Company also provided three forecasts of utility-sponsored DSM -- a base case scenario, which is NEPOOL's current forecast of Company-sponsored DSM savings, a low DSM scenario which discounts NEPOOL's projected DSM growth rates by ten percent, and a high DSM forecast, which inflates NEPOOL's projected DSM growth rates by ten percent. As noted above, although NEPOOL historically has overestimated DSM savings, the more recent NEPOOL forecasts have been lower and closer to actual savings. The Company's symmetrical ten percent adjustment of NEPOOL's DSM forecast is consistent with NEPOOL's trend to the successive lowering of its DSM forecasts and consistent with the DSM scenarios accepted by the Board in its most recent generating facility decision. See, Millennium Power Decision, EFSB 96-4, at 17-18.

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

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

(2) Supply Forecasts

(a) Description

i) Capacity Assumptions

ANP presented three supply scenarios -- base, high and low -- based in large part on the supply resources included in the 1997 CELT report (Exhs. BEL-1, at 2-10 to 2-20; HO-RR-12). The Company stated that it updated the 1997 NEPOOL supply forecast to reflect changes in the regional supply not included by NEPOOL (Exh. HO-RR-12, at 1 to 3). Specifically, beginning in 2000, the Company deducted the capacity of: (1) the Maine Yankee unit (794 MW), retired in July 1997; (2) the Middletown 1 unit (66 MW), and the Norwalk Harbor 10 unit (12 MW), both reactivated from deactivated reserve in 1996 as a temporary response to the Millstone unit outages; (3) the South Meadow 15 unit (42 MW), installed as a temporary response to the Millstone unit outages but since removed from the site; (4) the English 7 and 8, and Somerset Steam 5 units (141 MW), deactivated units which are included as reactivated units starting in 2002 even though the 1997 CELT report indicates that the owners have not decided whether to reactivate; and (5) the Bridgeport Harbor 1 unit (81 MW), which will be removed consistent with plans for new facility development at the site (Exhs. BEL-1, at 2-6; HO-N-8.1; HO-RR-3; HO-RR-3 supp.; HO-RR-12, at 1 to 3). ANP also added the capacity of: (1) the Wyman 1-3 units (223 MW); (2) the Indeck Jonesboro unit (49 MW), returned to service in 1998 following deactivation; and (3) the Devon 11-14 units (125 MW), installed as a temporary response to the Millstone outages and assumed by NEPOOL to retire in 2001 but recently granted permanent operating permits (Exhs. HO-RR-3; HO-RR-12 at 1 to 3; HO-RR-12, supp.).

The Company stated that, to reflect uncertainties in future capacity in its supply scenarios, it then adjusted the updated 1997 NEPOOL forecast by varying projections of: (1) the availability of existing fossil fuel-steam units; (2) the availability of existing nuclear units; and (3) the capacity of new projects currently being developed (id.; Exhs. BEL-1, at 2-10 to 2-20; HO-RR-12.3). ANP asserted that the CELT supply forecast overstates expected future capacity from existing nuclear units and fossil fuel steam units because it is simply a tabulation of all existing generating units based on their design or contract life without consideration of uncertainty in future availability (Exh. BEL-1, at 2-10). Specifically, the Company stated that the 1997 CELT report assumes (1) the continued operation of all active nuclear units in the region for the full terms of their current operating licenses even though these units are old and are facing significant regulatory, technical and economic issues, and (2) the limited retirement of existing fossil fuel steam units that have been in operation for more than 25 years even though 1,500 MW will be at least 40 years old by 2000 and 3,200 MW will be at least 40 years old by 2005 (id. at 2-10 to 2-16).

With respect to nuclear units, ANP stated that the Millstone 1 unit (641 MW) has been out of service since 1995 and that the Millstone 2 and 3 units (2030 MW) have been out of service since 1996 (Exh. HO-N-8.1). ANP stated that Northeast Utilities ("NU") has indicated its expectations that the Nuclear Regulatory Commission will approve the re-start of the Millstone 2 and 3 units by mid-1998 and has also indicated that it will examine whether to restart the Millstone 1 unit later in 1998 (Exh. HO-N-8.2). ANP stated that it is increasingly likely that the Millstone 1 unit will be retired (id.). ANP noted that the Connecticut Department of Public Utility and Control recently issued an order finding the Millstone 1 unit not used and useful based on NU's deferral of maintenance on this unit in favor of the Millstone 2 and 3 units and thus removed the Millstone 1 unit from rate base (id.).

ANP stated that the older fossil fuel steam units will typically require increased expenditures for operations and maintenance ("O&M") and performance degradation due to their age and potential capital costs to comply with Phase II of the Clean Air Act Amendments of 1990 ("CAAA") (id. at 2-16). The Company explained that many of these expenditures likely will be difficult to justify under restructuring due to competition from new generation technology which has significant efficiency, economic and environmental advantages (id. at 2-16 to 2-17).

In addition, the Company stated the 1997 CELT supply forecast does not include the capacity from all proposed new generating facilities that have reached significant licensing completion (Exh. HO-RR-6). The Company indicated that three new proposed generating facilities are fully licensed and under construction -- Berkshire Power Development

(265 MW), Dighton (170 MW), and Bridgeport Harbor, Connecticut (520 MW) (id.;

Exh. HO-RR-12, at 1 to 2). The Company also indicated that two new proposed generating facilities have reached significant licensing completion -- Tiverton, Rhode Island (250 MW), and Millennium (360 MW) (Exhs. HO-RR-6; HO-RR-12, at 1 to 2). The Company noted that there are development, licensing, financing and construction uncertainties that could affect the successful completion of projects not fully licensed and under construction

(Exh. BEL-1, at 2-20).

For the base supply scenario, the Company assumed reductions in the 1997 CELT forecast capacity based on retirement of (1) the Millstone 1 unit (641 MW), and

(2) 25 percent of the fossil-fired steam capacity that is at least 40 years old (386 MW in 2000 increasing to 908 MW in 2006) (Exhs. HO-N-9.1; HO-RR-5; HO-RR-12.3). In addition, the Company added 100 percent of the capacity of the new generating units that are fully licensed and under construction (955 MW) and 50 percent of the new generating units that have reached significant licensing completion (305 MW) (Exhs. HO-RR-6; HO-RR-12.3).

For the high supply scenario, the Company assumed that: (1) the Millstone 1 unit would be returned to service (641 MW); (2) ten percent of the fossil-fired steam capacity that is at least 40 years old would be retired (154 MW in 2000 increasing to 545 MW in 2006); (3) 100 percent of the capacity of the new generating units that are fully licensed and under construction would come on-line as scheduled (955 MW); and (4) 80 percent of the new generating units that have reached significant licensing completion would come on-line as scheduled (488 MW) (Exhs. BEL-1, at 2-17; HO-RR-12.4). For the low supply scenario, the Company assumed that: (1) the Millstone 1 and 2 units would be retired (1,512 MW);

(2) 50 percent of the fossil-fired steam capacity that is at least 40 years old would be retired (772 MW in 2000 increasing to 1816 MW in 2006); (3) 100 percent of the capacity of the new generating units that are fully licensed and under construction would come on-line as scheduled (955 MW); and (4) 20 percent of the new generating units that have reached significant licensing completion would come on-line as scheduled (122 MW) (Exhs. BEL-1,

at 2-17; HO-RR-12.4).

ii) Reserve Margin

The Company indicated that it adopted NEPOOL's most current projections of required reserve margins which are set forth in the September 1994 NEPOOL document, "1994 Annual Review of NEPOOL Objective Capability and Associated Parameters" (Exh. BEL-1, at 2-9). ANP stated that, in that document, NEPOOL specifies required reserve margins of 14.8 percent of adjusted peak load in 2000 and 15 percent of adjusted peak load starting in the year 2001 (id.; Exh. HO-N-7.1, at 6).

(b) Analysis

The Company has presented a base supply scenario which was based on the 1997 CELT report supply forecast, updated to reflect adjustments for actual, planned and likely changes to NEPOOL supply. In addition, to account for uncertainties in future availability, the Company then adjusted the updated 1997 NEPOOL forecast by varying projections of three categories of capacity to develop base, high and low supply scenarios. Here, the Siting Board considers the reasonableness of the Company's assumptions.

The Company's updates to the 1997 CELT report supply forecast included adjustments to reflect likely long-term status of units put in service as a temporary response to the Millstone outages. The Company deleted the capacity of older units that were reactivated from deactivated reserve and added the capacity of units put into service that received permanent operating permits. For purposes of this review, the Siting Board accepts the Company's assumptions.

As noted above, in the base case supply scenario, the Company assumed that

25 percent of the fossil fuel steam units that have been in operation for more than 25 years would be retired -- 386 MW in 2000 increasing to 908 MW in 2006. The Siting Board notes that it is reasonable to conclude that a portion of the units operating beyond retirement guidelines will be retired beginning in 2000, especially in light of CAAA requirements that are likely to take effect in 1999. In previous reviews the Siting Board has accepted assumptions that one unit operating beyond NEPOOL's guidelines for retirement, or a like amount of capacity, would be retired. See, Millennium Power Decision, EFSB 96-4, at 24; Berkshire Power Decision, 4 DOMSC at 270. The capacity reduction here for the year 2000 is consistent with previous reviews. Therefore, the Siting Board accepts the Company's assumption regarding retirement of fossil fuel steam units operating for more than 25 years.

The Company also assumed that the Millstone 1 unit would be retired in the base case supply scenario. The record demonstrates that the Millstone 1 unit has been out of service since 1995, that NU has not decided whether to restart the unit, that NU has deferred maintenance on the unit and that the Connecticut Department of Public Utility and Control has removed the unit from rate base. Therefore, for purposes of this review, the Siting Board accepts the Company's assumption of the retirement of the Millstone 1 unit. In addition, the Siting Board recognizes that it is appropriate to account for additional NUG resources that may commence operation during the forecast period. Here, the Company included 100 percent of the capacity of those units that are fully licensed and under construction and 50 percent of the capacity of those units that have reached significant licensing completion. The Company's criteria for including new proposed units is reasonable given the development, licensing, financing, and construction uncertainties that could affect the successful completion of units that are not fully licensed and under construction. Therefore, for purposes of this review, the Siting Board accepts the Company's assumptions regarding the inclusion of newly proposed units in the base case supply scenario.

Accordingly, the Siting Board finds that the Company's base supply scenario represents an appropriate base case supply forecast for use in the analysis of regional need. In addition, the Siting Board finds that the assumptions reflected in the Company's low case supply scenario are reasonable low case assumptions and therefore that the 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 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 2000 and 2001 and reasonably assumed that the reserve margins would remain at the projected values for the year 2001 in the years 2000 through 2006. Accordingly, consistent with recent Siting Board decisions, the Siting Board finds that the reserve margins projected by the Company are appropriate for purposes of this review.

(3) Need Forecasts

(a) Description

The Company developed nine need forecasts by adjusting the 1997 CELT summer peak load forecasts by each of three DSM scenarios, and combining each of the resulting three adjusted demand forecasts with three supply forecasts (Exh. HO-RR-13.2, 13.3, 13.4). Of these nine need forecasts, seven demonstrate a sustained need for at least 580 MW of capacity in 2000 and all demonstrate a sustained need for at least 580 MW of capacity in 2001 (id.).' See Table 1, below.

Table 1

RANGE OF REGIONAL NEED CASES

2000

Demand Case	DSM	High Supply	Base Supply	Low Supply
1997 CELT	High	(342)	(1,397)	(2,837)
1997 CELT	Base	(510)	(1,565)	(3,005)
1997 CELT	Low	(678)	(1,733)	(3,173)

2001

Demand Case	DSM	High Supply	Base Supply	Low Supply
1997 CELT	High	(651)	(1,770)	(3,315)
1997 CELT	Base	(825)	(1,944)	(3,489)
1997 CELT	Low	(998)	(2,117)	(3,662)

Source: Exhs. HO-RR-13.3, 13.4, 13.5.

Note: Capacity deficits are shown in parentheses.

(b) Analysis

In considering the Company's forecasts of summer and winter peak load, the Siting Board has found that the 1997 CELT forecast is an appropriate base case summer peak load forecast for use in the analysis of regional need for the years 2000 and beyond. In considering the Company's DSM forecasts, the Siting Board has found that: (1) the Company's base DSM scenario represents an appropriate base case forecast of DSM savings for use in the regional need analysis; (2) the Company's low DSM scenario represents an appropriate low case forecast of DSM savings for use in the regional need analysis; and (3) the Company's high DSM scenario represents an appropriate high case forecast of DSM savings for use in the regional need analysis.

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

The capacity positions under the summer and winter need forecasts based on the 1997 CELT summer peak load forecast for the years 2000 and 2001 are shown in Table 1, above. Of these nine need forecasts, seven demonstrate a sustained need for at least 580 MW of capacity in 2000 and all demonstrate a sustained need for at least 580 MW of capacity in 2001. Accordingly, the Siting Board finds that there is a sustained need for 580 MW or more of additional energy resources in New England for reliability purposes beginning in the year 2000.

b. Massachusetts

The Company asserted that there is a need for new capacity in Massachusetts by the year 2000 (Exh. BEL-1, at 2-25). To support its assertions, the Company presented a series of forecasts of demand and supply for Massachusetts, based primarily on NEPOOL’s 1997 CELT forecast prorated to Massachusetts (id. at 2-23 to 2-25; Exhs. HO-N-2, at 1; HO-RR-12.4; HO-RR-13.5). The Company stated that it then combined its demand and supply forecasts to produce a series of need forecasts (Exh. BEL-1, at 2-23).

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

(1) Demand Forecasts, DSM and Adjusted Load Forecasts

(a) Description

The Company indicated that it relied primarily on information contained in the 1997 CELT report and NEPOOL's most recent Massachusetts-specific forecast of adjusted summer peak load, which was published in 1994, to develop a Massachusetts peak load forecast (id.; Exhs. HO-N-2, at 1; HO-RR-13.5). The Company explained that it prorated the 1997 CELT unadjusted reference forecast by the ratio of the 1994 NEPOOL forecast for Massachusetts to the 1994 CELT reference forecast to develop a Massachusetts unadjusted reference forecast (Exhs. BEL-1, at 2-23; HO-N-2, at 1; HO-RR-13.5). The Company indicated that it applied the same 1994 ratios to the base, high and low DSM forecast and the NUG netted from load forecast in the 1997 CELT report and subtracted the prorated DSM and NUG netted from loads from the Massachusetts unadjusted reference forecast to develop Massachusetts adjusted forecasts (Exh. HO-RR-13.5).

The Company stated that it applied the same 1994 ratios to the 1997 CELT forecast high and low load forecasts to develop Massachusetts high case and low case forecasts, respectively (Exh. BEL-1, at 2-24).

Consistent with the regional need analysis, the Company provided the 1997 Massachusetts forecast of summer peak load, combined with the three aforementioned forecasts of DSM savings to develop forecasts of adjusted load (Exh. HO-RR-13.5).

(b) Analysis

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

The Siting Board reviewed the regional demand forecasts in Section II.A.2.a.(1), above. Consistent with its findings concerning the regional demand forecasts, the Siting Board finds that (1) the CELT report high case and low case demand forecasts for Massachusetts represent a sensitivity analysis of varying economic assumptions rather than forecasts of Massachusetts demand, and (2) the 1997 Massachusetts forecast of summer peak load is an appropriate base case peak load forecast for use in the analysis of Massachusetts need for the years 2000 and beyond.

With respect to DSM, the Company provided three forecasts of DSM savings corresponding to the forecasts of DSM savings presented in its regional need analysis. The Siting Board reviewed the regional DSM forecasts in Section II.A.2.a.(1), 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.

(2) Supply Forecast and Reserve Margin

(a) Description

ANP stated that it developed base, high and low supply scenarios for Massachusetts, consistent with its regional supply scenarios, with adjustments to reflect generating resource ownership and commitments of Massachusetts electric utility companies (Exh. BEL-1, at 2-24).

The Company stated that it used information in the 1997 CELT Report to determine, on a utility-by-utility basis, the capacity committed to utilities serving Massachusetts customers, including the total capability for utility generating capacity and non-utility capacity purchases claimed by utilities serving load exclusively within Massachusetts, combined with a percentage of the capability claimed by Massachusetts utilities that are part of holding companies serving load in multiple states including Massachusetts (id. at 2-24; Exh. HO-RR-12, at 3). The Company stated that it allocated an amount of these multi-state holding-companies' capacity to Massachusetts by calculating for each such holding company the ratio of Massachusetts peak load to total peak load on each system, and then using this ratio to apportion to Massachusetts the capacity of each generating facility owned by the holding company (Exh. HO-N-17).

The Company stated that its Massachusetts base, high and low case supply scenarios are comparable to the regional base, high and low case supply scenarios. In allocating the share of the projects currently under development to Massachusetts, ANP assumed that Massachusetts consumers would purchase output from these facilities in proportion to Massachusetts' share of the New England market (Exh. BEL-1, at 2-24).

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

(b) Analysis

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

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

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

(3) Need Forecasts

(a) Description

Consistent with its regional need forecasts, the Company developed nine summer need forecasts by adjusting the 1997 Massachusetts forecast by each of three DSM scenarios, and combining each of the resulting three summer adjusted demand forecasts with three supply forecasts (Exh. HO-RR-13.5, 13.6, 13.7). Of these nine summer need forecasts, all demonstrate a sustained need for at least 580 MW of capacity in 2000. See Table 2, below.

Table 2

RANGE OF MASS NEED CASES

2000

Demand Case	DSM	High Supply	Base Supply	Low Supply
1997 CELT	High	(912)	(1,172)	(1,528)
1997 CELT	Base	(991)	(1,252)	(1,607)
1997 CELT	Low	(1,071)	(1,332)	(1,687)

Source: Exh. HO-RR-13.5,13.6, 13.7

Capacity deficits are shown in parentheses.

(b) Analysis

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

The Siting Board has found that: (1) the Massachusetts high case and low case demand forecasts for Massachusetts represent a sensitivity analysis of varying economic assumptions rather than forecasts of Massachusetts demand, and (2) the 1997 Massachusetts forecast of summer and winter peak load is an appropriate base case peak load forecast for use in the analysis of Massachusetts need.

In considering the Company's DSM forecasts, the Siting Board has found that:

(1) the base Massachusetts DSM scenario represents an appropriate base case forecast of DSM savings for use in the Massachusetts need analysis; (2) the high Massachusetts DSM scenario represents an appropriate high case forecast of DSM savings for use in the Massachusetts need analysis; and (3) the low Massachusetts DSM scenario represents an appropriate low case forecast of DSM savings for use in the Massachusetts need analysis.

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

The capacity under the Massachusetts summer forecasts, based on the 1997 Massachusetts forecast, for the 2000 is shown in Table 2, above. All such summer need forecasts show a sustained need for at least 580 MW in 2000. Accordingly, the Siting Board finds that there is a sustained need for 580 MW or more of additional energy resources in Massachusetts for reliability purposes beginning in the year 2000.

3. <u>Economic Need</u>

a. <u>New England</u>

(1) <u>Description</u>

The Company asserted that there is an economic need in the region for the addition of more than 545 MW of low cost, high availability, base load capacity of the type offered by the proposed facility by the year 2000, both under the existing NEPOOL dispatch system and under a modified dispatch system consistent with electric industry restructuring (Exh. BEL-1, at 2-27). ANP explained that the proposed unit would provide significant cost advantages over other existing supplies in the market due to the replacement of lost nuclear capacity and displacement of more expensive fuels from the existing stock (Tr. 1, at 126).

(a) Existing NEPOOL Dispatch

In support of its assertions, the Company provided a series of detailed economic analyses based on modeling of existing NEPOOL economic dispatch practices for the 5-year period, 2000 through 2004, which compared the total incremental costs of two scenarios -- one that included the dispatch of the proposed facility ("ANP-in case") and another that lacked the proposed facility in the dispatch ("ANP-out case") (Exhs. BEL-1, at 2-28 to 2-19; HO-RR-20.1). The Company stated that these analyses demonstrate that the proposed facility would provide significant economic efficiency benefits to the region that would be equal to the difference of the region's cost of electricity under these two scenarios (Exh. BEL-1, at 2-30).

The Company stated that it used the ENPRO model to simulate NEPOOL's dispatch on an hourly basis over the forecast period (id. at 2-28). The Company stated that inputs into the model included: (1) generation supply identical to the base case supply scenario;

(2) load growth identical to the base peak load forecast; (3) the actual 1994 load duration curve; (4) operating and cost characteristics of individual generating facilities; (5) classification of specific units as must-run;(6) addition of new generic capacity to meet projected regional capacity requirements; (7) fuel price forecasts; and (8) operating characteristics of the proposed facility (id. at 2-28 to 2-30; Exhs. HO-RR-13.2; HO-RR-20.1). The Company noted that SO_2 allowance costs were explicitly incorporated into the economic dispatch (Exh. HO-RR-20.1).

The Company calculated energy efficiency savings for the years 2000 through 2004 based on meeting projected regional capacity requirements with generic combustion turbine ("CT") units ("CT scenario") (Exh HO-RR-20.5). The Company maintained that the CT scenario demonstrates the economic need for baseload capacity as opposed to peaking capacity (Exh. HO-N-19). However, the Company noted that an economically optimized expansion plan likely would include the addition of more baseload combined cycle ("CC") capacity than the capacity of the proposed facility (id.). In response to the Siting Board Staff, the Company also calculated energy efficiency savings based on meeting projected regional capacity requirements with generic CC units ("CC scenario") (Exh. HO-RR-20.5). ANP noted that its analysis assumes the same cost and performance characteristics for the generic CC capacity additions and the proposed facility (Exh. HO-RR-20.1).

The Company indicated that the model provided the NEPOOL system variable costs, new capacity fixed costs, and proposed facility costs associated with each set of assumptions (Exh. BEL-1, at 2-30 and app. G). The Company stated that the NEPOOL system-wide savings attributable to the proposed facility would be the difference in total costs between the ANP-in case and ANP-out case (id. at 2-28 to 2-29). The Company stated that the annual nominal savings over the 2000 to 2004 period were discounted to mid-year 2000 to obtain the net present value ("NPV") of economic efficiency savings attributable to the proposed project (Exh. HO-RR-14).

The Company indicated that under the existing NEPOOL dispatch practices and the CC scenario, the proposed project would result in savings with a NPV of $17 million in year 2000 dollars over the five-year forecast period (Exh. HO-RR-20.5). The Company indicated that the annual cost savings would be $2.6 million in 2000, $4.2 in 2001,

$6.1 million in 2002, $4.4 million in 2003, and $4.0 million in 2004 (id.).

(b) Dispatch Under Deregulated Generation Market

ANP asserted that the proposed project would provide regional energy efficiency benefits under deregulation because introduction of the proposed project into the market would cause the market clearing price of energy to decline, leading to a reduction in the total payment for energy for the region (Exh. BEL-1, at 2-33, 2-38). The Company stated that in a deregulated market, suppliers will offer power to the market for a bid price and the Independent System Operator will purchase power from the suppliers in order of bid prices, starting with the lowest bids, up to the need for each hour (id. at 2-38; Tr. 1, at 100-101). The Company also stated that all suppliers will be paid the market clearing price -- the bid price of the most expensive unit dispatched in each hour (Tr. 1, at 99-101). The Company explained that the total energy revenues would equal the market clearing price multiplied by the energy demand in the region (Exh. BEL-1, at 2-38).

The Company provided a series of detailed economic analyses based on modeling regional dispatch under a deregulated generation market for the five-year period 2000 through 2004 which compared the total payment for energy for the ANP-in and ANP-out cases (id.; Exh. HO-RR-20). Consistent with the existing NEPOOL dispatch analysis, the Company estimated total payment for energy based on two different scenarios of generic capacity additions to meet the projected regional capacity requirements -- the CT scenario, and the CC scenario (Exh. HO-RR-20).

The Company indicated that savings would be greater under the deregulated generation market dispatch than under the NEPOOL dispatch (Exh. HO-RR-20.5, 20.5B). The Company indicated that under the deregulated generation market and the CC scenario, the proposed project would result in savings with a NPV of $583 million over the five-year forecast period (Exh. HO-RR-20.5B). The Company indicated that the annual cost savings would be $127.5 million in 2000, $129.0 in 2001, $141.5 million in 2002, $153.2 million in 2003, and $158.6 million in 2004 (id.).

(2) Analysis

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

4 DOMSB at 292-93; NEA Decision, 16 DOMSC at 344-360.

In previous reviews of non-utility proposals to construct electric generation projects, project proponents have argued that additional energy resources were needed in the region based on economic efficiency grounds, i.e., that the construction and operation of a particular project would result in a significant reduction in total cost of generating power in the New England region through the displacement of more expensive sources of power. Millennium Power Decision, Berkshire Power Decision, 4 DOMSB at 285-292; 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. Millennium Power Decision, EFSB 96-4, at 40; Berkshire Power Decision, 4 DOMSB at 295-96; Enron Decision, 23 DOMSC at 55-62. The Siting Board has noted that such findings, based on a comprehensive analysis of NEPOOL dispatch, both with and without each proposed project, are necessarily project-specific. The Siting Board also has identified the magnitude and timing of such gains as critical to its review. See Berkshire Power Decision,

4 DOMSB at 293.

Here, the Company has provided a five-year analysis of economic efficiency savings with a detailed description of its methods and assumptions under two different dispatch scenarios and two different generation expansion scenarios. The Company states that the CT scenario demonstrates the economic need for baseload capacity as opposed to peaking capacity but noted that an economically optimized expansion plan likely would include new baseload CC capacity in addition to the proposed facility. Here, the Siting Board focuses on the CC scenario, the more realistic of the two scenarios.

In developing the CC scenario, the Company assumed the same efficiency for the generic CC units and proposed project. In previous cases the Siting Board has expressed concern over companies' assumption of efficiency advantages for their projects relative to generic units and the lack of efficiency improvements for generic units, particularly in the long term. See Millennium Power Decision, EFSB 96-4, at 40-41. Here, although the Company does not assume any efficiency improvements for later generic units, its assumption of equal efficiency is reasonable, given the short five-year time frame of the analysis.

The analyses provided by the Company indicate that under both dispatch scenarios, the proposed project would provide substantial economic efficiency savings over the five-year period from 2000 to 2004, ranging from $17 million in year 2000 dollars under the existing NEPOOL dispatch scenario to $583 million in year 2000 dollars under the deregulated generation market dispatch scenario.

Accordingly, the Siting Board finds that the Company has established that there will be a need in New England for the additional energy resources produced by the baseload operation of the proposed project for economic efficiency purposes in the years 2000 through 2004.

b. Massachusetts

(1) Description

To demonstrate Massachusetts economic efficiency benefits, the Company allocated a pro rata share of the regional economic efficiency benefits to Massachusetts based on the ratio of Massachusetts energy requirements to NEPOOL energy requirements (Exhs. HO-RR-16; HO-RR-20).

Assuming existing NEPOOL dispatch and the CC scenario, the Company estimated that the proposed project would result in savings with a NPV of $8 million in Massachusetts over the five year forecast period (Exh. HO-RR-20.5). The Company indicated that the annual cost savings for Massachusetts would be $1.2 million in 2000, $2.0 million in 2001, $2.8 million in 2002, $2.0 million in 2003, and $1.9 million in 2004 (id.).

Assuming deregulated generation market dispatch and the CC scenario, the Company estimated that the proposed project would result in savings with a NPV of $272 million in Massachusetts over the five year forecast period (Exh. HO-RR-20.5B). The Company indicated that the annual cost savings for Massachusetts would be $59.2 million in 2000, $60.3 million in 2001, $65.8 million in 2002, $71.1 million in 2003, and $73.5 million in 2004 (id.).

(2) Analysis

In Section, II.A.3.a., above, the Siting Board found that there would be a need in New England for 545 MW of additional energy resources from the proposed project for economic efficiency purposes beginning in 2000. In addition, the Company provided analyses that estimated the extent of savings that would accrue to Massachusetts -- savings due to the operation of the proposed facility that would be $8 million under existing NEPOOL dispatch and $272 million under a deregulated generation market dispatch, discounted to year 2000 dollars, over the 2000 to 2004 time period.

Accordingly, the Siting Board finds that there will be a need in Massachusetts for the additional energy resources produced by the baseload operation of the proposed project for economic efficiency purposes in the years 2000 through 2004.

4. Environmental Need

a. New England

(1) Description

The Company asserted that the operation of the proposed facility would provide the region with substantial net benefits in the form of reduced system-wide emissions of pollutants, due to the proposed facility's displacement of generating facilities that are less efficient and have higher air pollutant emission rates (Exh. BEL-1, at 2-41). In support, the Company presented dispatch analyses based on existing NEPOOL dispatch practices, which compare the total system-wide emissions of sulfur dioxide ("SO_2"), NOx and carbon dioxide ("CO_2") under two scenarios -- the ANP-in case and the ANP-out case (id. at 2-41 to 2-42; HO-RR-20.9, 20-10). The analyses were based on meeting projected regional capacity requirements under both a CT scenario and CC scenario (Exh. HO-RR-20.9, 20.10).

ANP indicated that it used the ENPRO model with assumptions consistent with the economic dispatch analysis and plant-specific emissions data to determine regional emissions for each pollutant in tons per year ("tpy") (Exh. BEL-1, at 2-41 to 2-42). The Company stated that emission rates for: (1) the proposed facility and generic CCs were based on plant-specific data for the proposed facility; (2) all existing utility units larger than 25 MW were based on 1996 actual data from the EPA's Continuous Emissions Monitoring System ("CEMS"); (3) existing NUG units, not included in CEMS, were based on the emission rates for the NEP Manchester Street CC facility; (4) existing peaking units were based on 1995 GTF report assumptions for SO_2 and NOx and on emission rates for the Cleary 9 unit for CO_2; and (5) generic CTs were based on 0.3 percent sulfur oil, EPRI TAG NOx assumptions and on emission rates for the Cleary 9 unit for CO_2 (Exhs. BEL-1, at 2-42; HO-RR-17; HO-RR-20). The Company noted that the emissions rates for existing units were based on historical data and therefore did not reflect any reductions that may be required as a result of Phase II of the CAAA (Exh. HO-N-20). However, as noted above, the Company incorporated SO_2 allowance costs into the analysis (Exh. HO-RR-20.1). The emissions analysis assumes constant emission rates and oil/gas mix for dual fuel units over the five-year forecast period (Exhs. HO-N-29(conf.); HO-RR-20.1).

The Company's analysis indicated that, under the CC scenario, emissions of SO_2, NOx and CO_2 would be reduced in the ANP-in case, compared to the ANP-out case, over the five-year period from 2000 through 2004 (Exh. HO-RR-20.10). Specifically, the Company's analysis indicated reductions over the five years of: (1) 76,773 tons of SO_2, or 9.4 percent of regional emissions; (2) 20,462 tons of NOx, or 8.1 percent of regional emissions; and

(3) 7.0 million tons of CO_2, or 3.2 percent of regional emissions (id.).

The Company also compared the emission reductions attributable to the ANP project, as developed in its displacement analysis for the CC scenario, to the emissions impacts of the proposed facility (Exh. HO-N-25.2). This comparison shows that the five-year emissions reductions for SO_2, 76,773 tons, would be significantly larger than the proposed facility's SO_2 emissions of 242 tons over the same period (Exh. HO-N-25.2). Similarly, the five-year emissions reductions for NOx, 20,462 tons, would be significantly larger than the proposed facility's NOx emissions of 953 tons over the same period (id.). With respect to CO_2, the Company's analyses show that five-year emissions reductions, 7.0 million tons, would be

85 percent of the proposed facility's CO_2 emissions of 8.3 million tons over the same period (id.).

(2) 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. Millennium Power Decision, EFSB 96-4, at 46; Berkshire Power Decision,

4 DOMSB at 300; Altresco Lynn Decision, 2 DOMSB at 99. See also, Enron Decision, 23 DOMSC at 71; MASSPOWER Decision, 20 DOMSC at 388.

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

Decision, 2 DOMSC at 328; Altresco Lynn Decision, 2 DOMSB at 100; EEC (remand) Decision, 1 DOMSB at 332-333. In a more recent review of a gas-fire combined-cycle ("GTCC") facility, the Siting Board raised concerns regarding assumed characteristics of future generic GTCC units in the dispatch analysis, including assumed efficiency and size relative to the proposed project. Millennium Power Decision, EFSB 96-4, at 46; Berkshire Power Decision, 4 DOMSB at 302.

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. Millennium Power Decision, EFSB 96-4, at 47; Cabot Decision, 2 DOMSB at 327; EEC (remand) Decision, 1 DOMSB at 333. In the EEC (remand) Decision, the Siting Board further recognized that, to the extent that the applicant's project would in whole or in part replace existing generation that potentially will be retired, there would be significant potential for that project to provide long-term benefits through displacement of such generation. 1 DOMSB at 333.

Here, the Company has provided a comprehensive five-year analysis of dispatch effects on regional emissions for the period from 2000 through 2004. The Company's analysis includes sufficient documentation regarding the methods and assumptions used in its calculations for the Siting Board to evaluate whether there would be significant dispatch-related emissions reductions specific to the operation of the proposed project.

The Company's analytical methods are similar to those used in past Siting Board reviews of generating facilities, although the time frame and some other elements of the analysis are different. Responding to concerns in past Siting Board reviews, the Company has focused its displacement analysis on the short run and also has assumed the same efficiency for generic CC units and the proposed project. In addition, the Company's base supply case assumes retirement of 25 percent of aging fossil fuel steam units over the forecast period. This assumed retirement rate responds to concerns the Siting Board has identified in past reviews with respect to (1) assumed redispatch of displaced generation over time with continued load growth and (2) failure to address the potential for significant amounts of retirement of existing generating units.

The record also shows, however, that the displacement analysis covers a period in which significant amounts of new capacity are needed to offset load growth and earlier than expected losses of nuclear capacity; such needs potentially reduce the shares of new generation that would be available to permanently displace existing fossil fuel generating capacity. Further, the Company's displacement analysis does not explicitly identify and analyze displacement scenarios based on differential amounts of retirement of fossil fuel generation. Thus it is unclear that the overall trends in generation mix reflected in the Company's analyses would necessarily demonstrate significant progress in meeting environmental goals.

At the same time, the Siting Board notes that the Company was able to demonstrate, through its displacement analysis, net reductions in five-year regional SO_2 and NOx emissions inclusive of the proposed facility's emissions that significantly exceed the proposed facility's SO_2 and NOx emissions over the same period. The Company's displacement analysis shows regional CO_2 emissions net reductions which are 85 percent of the proposed facility's CO_2 emissions.

The Company has established that operation of the proposed project would result in reductions in regional emissions of NOx, SO_2, and CO_2, including reductions in emissions of SO_2 and NOx that exceed the proposed facility's own emissions. Accordingly, the Siting Board finds that, on balance, the Company has established that there will be a need in New England for the additional energy resources produced by the baseload operation of the proposed project for environmental purposes in the years 2000 through 2004.

b. Massachusetts

(1) Description

To demonstrate environmental need for Massachusetts, ANP provided a dispatch analysis based on existing NEPOOL dispatch practices, which compares the emissions of SO_2, CO_2 and NOx from generating units physically located in Massachusetts under two scenarios -- the ANP-in case and the ANP-out case (Exhs. HO-RR-19; HO-RR-2012, 20-13). The analyses were based on meeting projected regional capacity requirements under both a CT scenario and CC scenario (Exh. HO-RR-20.12, 20.13).

The Company's analysis indicated that, under the CC scenario, emissions of SO_2, NOx and CO_2 would be reduced in the ANP-in case, compared to the ANP-out case, over the five-year period from 2000 through 2004 (Exh. HO-RR-20.10). Specifically, the Company's analysis indicated reductions over the five years of: (1) 42,794 tons of SO_2, or 9.5 percent of Massachusetts emissions; (2) 10,913 tons of NOx, or 7.9 percent of Massachusetts emissions; and (3) 587,264 tons of CO_2, or 0.5 percent of Massachusetts emissions (id.).

(2) Analysis

The Siting Board recognizes the complexity in estimating pollutant emissions for Massachusetts due to the transportation of pollutants across state lines and the uncertainty regarding the location of facilities to be developed in the future. The Company's approach for estimating Massachusetts emissions benefits by including all generating units physically located in Massachusetts is reasonable. The Company's analysis demonstrates emissions reductions in Massachusetts for SO_2, NOx and CO_2 over the five-year analysis period.

Accordingly, the Siting Board finds that there will be a need in Massachusetts for the additional energy resources produced by the baseload operation of the proposed project for environmental purposes in the years 2000 through 2004.

5. Conclusions on Need

The Siting Board has found that there will be a sustained need for 580 MW or more of additional energy resources in New England for reliability purposes beginning in the year 2000. In addition, the Siting Board has found that there will be a sustained need for 580 MW or more of additional energy resources in Massachusetts for reliability purposes beginning in the year 2000.

The Siting Board also has found that, consistent with its findings regarding reliability need in New England, there will be a need in New England for the additional energy resources produced by the baseload operation of the proposed project for economic efficiency purposes in the years 2000 through 2004. In addition, the Siting Board has found that there will be a need in Massachusetts for the additional energy resources produced by the baseload operation of the proposed project for economic efficiency purposes in the years 2000 through 2004.

Further, the Siting Board has found that there will be a need in New England for the additional energy resources produced by the baseload operation of the proposed project for environmental purposes in the years 2000 through 2004. In addition, the Siting Board has found that there will be a need in Massachusetts for the additional energy resources produced by the baseload operation of the proposed project for environmental purposes in the years 2000 through 2004.

Based on a showing of a sustained need for 580 MW or more of additional energy resources in the Commonwealth for reliability purposes, combined with a need for the additional energy resources provided by the baseload operation of the proposed project for both economic and environmental purposes in the years 2000 through 2004, the Siting Board finds that the proposed project is needed to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost, beginning in the year 2000.

B. Alternative Technologies Comparison

1. Standard of Review

G.L. c. 164, § 69H, requires the Siting Board to evaluate proposed projects in terms of their consistency with providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. In addition, G.L. c. 164, § 69J, requires a project proponent to present "alternatives to planned action" which may include: (a) other methods of generating, manufacturing, or storing, and other site locations; (b) other sources of electrical power or gas, including facilities which operate on solar or geothermal energy and wind, or facilities which operate on the principle of cogeneration or hydrogeneration; and (c) no additional electric power or gas.

In implementing its statutory mandate, the Siting Board requires a petitioner to show that, on balance, its proposed project is superior to alternate approaches in the ability to address the previously identified need in terms of cost, environmental impact and reliability. Millennium Power Decision, EFSB 96-4, at 51 to 52; Berkshire Power Decision, 4 DOMSB at 304; Cabot Decision, 2 DOMSB at 334.

2. Identification of Resource Alternatives

a. Description

To address the identified need for additional energy resources, the Company proposes to construct a nominal net 580-MW gas-fired, combined-cycle facility in Bellingham, Massachusetts, which would commence commercial operation in the second quarter of the year 2000 (Exh. BEL-1, at 1-1 to 1-2). The Company indicated that the proposed project would operate with an approximate heat rate of 6700 Btu/KWh and an availability factor of 92 percent (id. at 3-21).

The Company stated that it used a three-phase screening process to examine all reasonable alternative technologies (Exh. BEL-1, at 3-2). The Company stated that, as a first step, it compiled a list of electric generating technologies capable of operating, like the proposed project, in baseload or intermediate mode, and then subjected each technology to a fatal flaw analysis, i.e., it evaluated each technology for siting/permitting feasibility, maturity, cost effectiveness, and suitability under regional policy guidelines (id. at 3-3 to 3-4). The Company indicated that, in selecting technologies for further evaluation in phase two, it conservatively included technologies which appeared to be at least marginally viable in terms of meeting the identified need (id. at 3-4). The phase one evaluation resulted in a list of nine potentially viable technologies: (1) gas-fired combined cycle ("GCC"); (2) coal-fired atmospheric fluidized bed ("AFB"); (3) coal-fired pressurized fluidized bed ("PFB"); (4) integrated coal gasification ("CG"); (5) pulverized coal ("PC"); (6) wind energy;

(7) municipal solid waste; (8) biomass; and (9) fuel cells (id. at 3-3 to 3-4).

The Company stated that it initially based its phase one review and fatal flaw analysis on the latest publicly available copies of two documents, the EPRI Technical Assessment Guide: Electricity Supply - 1993, EPRI TR-102275-V1R7 ("TAG"), and the 1995 NEPOOL Summary of Generation Task Force Long-Range Study Assumptions ("GTF Report") (id.). The Company also identified sources more current than the 1993 TAG and the 1995 GTF Report for information on technology alternatives in response to the Siting Board's directive, established in its Millennium Power Decision, EFSB 96-4 at 55, n.61, that future project proponents use current TAG data or pursue alternative sources (Exh. HO-A-11). The Company submitted cost and performance assumptions from its alternative sources which were within the range of estimates from the 1993 TAG (Exh. HO-A-11.1).

The Company stated that, because it did not have access to the most recent TAG data, it investigated alternative sources of information, including information available from the Department of Energy ("DOE") and affiliated organizations, as well as other publicly available information on the AFB, PFB, CG, PC and wind energy alternatives (Exh. HO-

A-11S). The Company provided a summary of the results of its research, including a description of the 1993 TAG analysis of each of the considered technologies, a description of new projects identified, a summary of any recent technological improvements, and the Company's assessment of any updates to the 1993 TAG data indicated as a result of its research (id.; Exh. HO-A-11.1). At the request of the Siting Board, the Company also provided a range of recent (published 1997) cost and performance data for technology alternatives eliminated in phase one, including solar energy (Exhs. HO-RR-22, HO-RR-22.1, HO-RR-23.2(red.)). In addition, the Company provided information in support of its view that distributed generation of such technology alternatives as diesel engines, combustion turbines, fuel cells, wind power and photovoltaic cells would not be a practical alternative to the proposed project because of potential permitting difficulties, lack of technical maturity, and inadequate availability of power (Exhs. HO-A-10; HO-RR-21; HO-RR-21.1; HO-RR-22; HO-RR-22.1).

The Company stated that phase two of its analysis involved narrowing the group of nine potential technologies identified in phase one to a group of reasonably practical alternatives based on the following five criteria: technical maturity; siting/permitting feasibility; reliability; cost-effectiveness; and ability to meet the identified need at a single site (Exh. BEL-1, at 3-9). The Company stated that while its phase two criteria were similar to its phase one criteria, phase two criteria were distinguished by tighter thresholds (id.). Those technologies failing to meet the standard for two or more phase two criteria were eliminated from further review (id.).

Based on its phase two analysis, the Company concluded that the wind energy, municipal solid waste, biomass and fuel cell technologies were not reasonably practical alternatives for the following reasons:

Technology Eliminated	Rationale
Wind Energy	Rated "demonstration" (rather than "mature" or "commercial" by Tag Report); reliability constraints due to intermittent nature of resource; multiple sites, with associated increase in environmental impacts and permitting issues, required to construct wind energy facilities capable of producing 545 MW
Municipal Solid Waste	Permitting constraints due to emissions and fact that MA has reached 50 percent limit for power generation from combustible waste established by state policy; relatively higher cost/kWh; multiple sites, with associated increase in environmental impacts and permitting issues, required to construct municipal solid waste facilities capable of producing 545 MW

Biomass	High cost/kWh; multiple sites, with associated increase in environmental impacts and permitting issues, required to construct biomass facilities capable of producing 545 MW
Fuel Cells	Rated "demonstration" (rather than "mature" or "commercial" by Tag Report); relatively higher cost/kWh; multiple sites, with associated increase in environmental impacts and permitting issues, required to construct fuel cells capable of producing 545 MW

(id. at 3-6 to 3-9).

The Company therefore narrowed its list of potential technology alternatives for the proposed project to the GCC, AFB, PFB, CG and PC technologies (id. at 3-9 to 3-14). Thus, in addition to the proposed project, five technology alternatives advanced to the third phase of the Company's technology alternatives analysis (id. at 3-14). The Company indicated that the third phase of its analysis compared the environmental impacts and costs of the technology alternatives to those of the proposed project (id.).

b. Analysis

The record demonstrates that the Company narrowed the number of potential alternative technologies in two stages, to nine and then to five. 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 and eliminated technologies failing to meet two or more of the Company's stated criteria. The record demonstrates that the Company used standard industry procedures to scale each evaluated technology alternative to the size of the proposed project, and appropriately analyzed the possibility of using distributed generation to supply the identified need for energy.

Thus the record demonstrates that all technologies have been evaluated based on the same output and criteria. The Siting Board finds that the proposed project, the GCC and the coal-fired AFB, PFB, CG and PC alternatives are comparable in terms of their ability to meet the identified need. Because the record demonstrates that the GCC technology alternative is in no respect superior to the proposed project, the Siting Board will not review it further. Therefore, in reviewing the cost and environmental impacts of the proposed project, the Siting Board compares the proposed project to each of four technology alternatives: AFB, PFB, CG and PC.

3. Environmental Impacts

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

The Company stated that, to the extent possible, the alternative technologies and the proposed project were compared based on the same level of net electric output, 545 MW, and assumed to begin commercial operation at the same time, in the second quarter of the year 2000 (Exh. BEL-1, at 1-1 to 1-2, 3-2).

In addition, the Company indicated that: (1) the AFB generator operates at a full load heat rate of 9,796 Btu/kWh and has an equivalent availability of 90.4 percent; (2) the PFB generator operates at a full load heat rate of 8,959 Btu/kWh and has an equivalent availability of 80.8 percent; (3) the CG generator operates at a full load heat rate of 8,090 Btu/kWh and has an equivalent availability of 85.7 percent; and (4) the PC unit operates at 9,618 Btu/kWh and has an equivalent availability of 85.5 percent (id. at 3-21). The Company noted that the proposed project offers a higher projected availability factor, 92 percent, and lower heat rate, 6,700 Btu/kWh, than any of the alternative technologies (Exh. BEL-1, at 3-21; see Table 4, Section II.B.4.a, below).

The Company indicated that it gathered the bulk of its cost and performance data for the technology alternatives from vendors for the proposed project and from the 1993 TAG (Exh. BEL-1, at 3-12; Tr. 2, at 93 to 95).

a. Air Quality

The Company asserted that the proposed project would be preferable to the four alternative technologies with respect to air quality (Exh. BEL-1, at 3-15). In support of its assertion, the Company provided an analysis of the average annual emission rates and the total annual emissions of SO_2, NOx, PM-10, CO, VOCs and CO_2 for the proposed project and the technology alternatives (id. at 3-24). For the proposed project, the Company stated that emissions reflect power augmentation throughout the year, but that generation output was based on the base 545 MW annual average (id. at 3-15). The Company stated that emissions for the coal alternatives were calculated based on data from various sources, including the EPA's RACT/BACT/LAER clearinghouse and the 1995 GTF Report, and are considered to represent RACT, BACT and LAER technologies (id.).

The Company stated that the proposed project would produce lower annual emissions of SO_2, NOx, CO and CO_2 than each of the evaluated alternatives (id. at 3-15, 3-24). The Company originally indicated that emissions of PM-10 and VOCs from the proposed project would be the same as or slightly higher than the same emissions from the AFB, PFB and CG alternatives. However, the Company subsequently submitted revised VOCs emission figures from its turbine vendor which indicated that VOCs emissions would be reduced to 33 tons/year (.0032 lbs/MMBTU), a level considerably lower than any of the evaluated alternatives (Exhs. BEL-13.2; BEL-1, at 3-24; Company Brief at 53). See Table 3, below.

Table 3

Alternative Technologies - Pollutant Emissions

	ANP-Bellingham*	AFB	PFB	CG	PC
Ann. average emission rates (lbs/MMBTU)					
SO_2	0.0055	0.21	0.129	0.078	0.16
NOx	0.0127	0.10	0.10	0.035	0.17
PM-10	0.0138	0.015	0.018	0.013	0.018
CO	0.0055	0.13	0.18	0.056	0.10
VOC	0.0032	0.005	0.004	0.007	0.0036
	112				

CO_2		204	204	204	204
Ann. emissions (tpy), based on assumed availability factor					
Availability Factor	92%	90.4%	80.8%	85.7%	85.5%
SO_2	82	4439	2229	1291	3128
NOx	186	2114	1728	579	3324
PM-10	203	317	311	215	352
CO	82	2748	311	927	1955
VOC	33	106	69	116	70
CO_2 (1,000 tpy)	1,648	4,312	3,525	3,376	3,989

Source: Exhs. BEL-1, at 3-24; BEL-13.2, App. B.

* Emissions for ANP-Bellingham, with the exception of VOCs, are initial estimates. Actual emissions for some pollutants are likely to be lower as a result of on-going refinement of the proposed project.

The record demonstrates that, considering all pollutants, the annual emissions of the proposed project would be lower than those of the four technology alternatives. Accordingly, the Siting Board finds that the proposed project is preferable to the AFB, PFB, CG and PC alternatives with respect to air quality.

b. Water Supply and Wastewater

The Company asserted that each of the coal-fired alternatives would require a significantly greater water supply and would generate significantly greater amounts of wastewater than the proposed project (Exh. BEL-1, at 3-15 to 3-16).

The Company indicated that the proposed project, which incorporates dry mechanical cooling, will not require cooling water, but will require water volumes for steam augmentation purposes above and beyond base-load water requirements. The Company indicated that base-load water supply needs for the proposed facility, including potable water supply, would be approximately 14,000 gallons per day ("gpd") (Exh. BCC(2)-WW4.1;

Tr. 10, at 129). The Company indicated that, with the likely maximum use of steam augmentation, total average daily water use for the proposed project would be 179,000 gpd based on 302.2 days of operation per year (Tr. 11, at 52).

The Company stated that the amount of water necessary for the coal-fired technology alternatives is a function of the size of the steam turbine and coal handling/processing requirements (Exh. BEL-1, at 3-16). With respect to water supply needs, assuming dry mechanical cooling and a steam turbine in all cases, the Company stated that the AFB alternative would require 3,787,705 gpd based on use of a 545 MW turbine; the PFB alternative, with a 436 MW turbine, would require 3,030,164 gpd; the CG alternative would use a 202 MW turbine and require 1,403,954 gpd; and the PC alternative, with a 545 MW turbine, would require 3,787,705 gpd (id. at 3-16, 3-25).

The Company indicated that, with the exception of occasional periods of special maintenance activity, the maximum process wastewater discharges for the proposed project would be approximately 8,000 gpd (Exhs. BEL-15, at 12-5; NEA-13). The Company stated that steam augmentation would not increase these volumes (Tr. 11, at 138). The Company indicated that process wastewater would be significantly higher for the considered technology alternatives, with the exception of the PC alternative which is assumed to have no process wastewater discharge due to its use of wastewater for scrubber makeup water (Exh. BEL-1,

at 3-16, 3-25). The Company indicated that process wastewater for the AFB, PFB and CG alternatives would be 427,395 gpd, 341,916 gpd and 698,718 gpd, respectively (id. at 3-25).

The record demonstrates that the water supply requirements of the proposed project would be approximately 13 percent of the water supply requirements of the CG alternative, and approximately five percent of the water supply requirements of each of the AFB, PFB and PC alternatives. Accordingly, the Siting Board finds that the proposed project is preferable to the AFB, PFB, CG and PC alternatives with respect to water use.

The record further demonstrates that the wastewater generated by the proposed project would be two percent of the wastewater generated by the AFB and PFB alternatives, and one percent of the wastewater generated by the CG alternative, but would be greater than the wastewater generated by the PC alternative by 8,000 gpd. Accordingly, the Siting Board finds that the proposed project is preferable to the AFB, PFB and CG alternatives, but that the PC alternative is preferable to the proposed project with respect to wastewater discharge.

c. Noise

The Company asserted that the proposed project would be preferable to the AFB, PFB, CG and PC alternatives with respect to noise impacts (Exh. BEL-1, at 3-16).

In comparing the noise impacts of the proposed project to that of the technology alternatives, the Company 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 (id.). The Company stated, however, that the coal-fired alternatives would have added sources of noise due to coal usage which would be difficult to mitigate, including intermittent noise due to coal delivery and relatively continuous noise from coal crushing (id.). The Company stated that noise sources at the CG alternative, in addition to noise sources common to the other coal-based alternatives, would include the flare stack of the coal gasification plant (id.).

The record demonstrates that delivery and crushing of coal would increase noise impacts of the AFB, PFB, CG and PC alternatives relative to the proposed project.

Accordingly, the Siting Board finds that the proposed project is preferable to the AFB, PFB, CG and PC alternatives with respect to noise impacts.

d. Fuel Transportation

The Company asserted that the proposed project would be preferable to the coal-fired alternatives with respect to fuel transportation impacts (Exh. BEL-1, at 3-18). The Company stated that natural gas would be delivered to the site via an existing high-pressure interstate pipeline approximately one mile from the proposed site. The Company indicated that a new pipeline interconnect would be constructed from the proposed project to the existing facilities, with potential impacts to wetlands (id. at 3-17).

The Company stated that the four coal-fired alternatives would require rail delivery of coal as a practical matter and that the lack of rail access at the preferred site would make unlikely the construction there of a coal-fired project (id.).

With respect to transportation of fuel, the Company indicated that the coal-fired alternatives would require delivery of coal in quantities ranging from 1,248,120 tons per year for the CG alternative to approximately 1,594,205 tons per year for the AFB alternative (id. at 3-26). The Company indicated that the CG alternative, which would require less coal than the other considered coal-fired alternatives, would require 12,481 100-ton railcar-loads of coal, equivalent to more than 120 arrivals and departures per year, or at least two per week (id. at 3-17, 3-26). The Company stated that in addition to the coal deliveries, the PC alternative would require limestone or lime deliveries for SO_2 control (id. at 3-17). The Company stated that a coal-fired project would likely be sited in close proximity to existing rail lines with adequate capacity to accommodate coal deliveries, but that delivery of coal by rail would nonetheless likely involve additional impacts to other rail users and the communities through which the deliveries would pass (id.). The Company further stated that the coal-based alternatives would require 30 days' on-site fuel storage, which would not be true of the proposed project (id.).

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.

The record demonstrates that the proposed project would limit fuel transportation impacts by connecting to existing high-pressure interstate pipeline facilities, but construction of a new pipeline interconnect from the proposed project to the existing facilities would likely involve impacts to wetlands. The record also demonstrates, however, that transportation of coal by rail would likely result in greater impacts overall and over time than would transportation of natural gas by pipeline.

Accordingly, the Siting Board finds that the proposed project would be preferable to the AFB, PFB, CG and PC alternatives with respect to fuel transportation impacts.

e. Land Use

The Company asserted that the proposed project would be preferable to the coal-fired alternatives with respect to land use impacts (Exh. BEL-1, at 3-18). The Company indicated that it included both total land requirements and impacts to surrounding uses in evaluating the land use impacts of the proposed project and alternatives (id.). The Company indicated that the project's tallest structures would be the two 180-foot stacks and two 110-foot air cooled condensers (id. at Figure 1.3-1). The Company indicated that construction of the proposed project would permanently alter 20.8 acres of the project site, a 125-acre, mostly wooded area, zoned industrial, and predominantly surrounded by forested land also zoned industrial, with some proximate areas of residential and recreational use (id. at 1-8, 6-65 to 6-66).

The Company stated that the coal-fired alternatives each would require at least 40 acres for the facility footprint, rail unloading and fuel storage areas (id. at 3-18). The Company stated that, in addition, the coal-fired alternatives would require a greater number of structures than the proposed project and that the scale of such structures, including the height of the buildings, stacks and cooling towers, would be significantly larger than the components of the proposed project (id.).

The record demonstrates that the proposed project would require 20.8 acres within the proposed 125-acre site. The record further demonstrates that the scale and number of buildings required by the coal-fired alternatives would be greater than those required by the proposed project.

The Siting Board notes that on the basis of the size of the proposed site alone, construction there of the coal-fired alternatives as well as the gas-fired alternatives would likely be possible. The Siting Board further notes, however, the greater potential for a variety of land use impacts, including local noise and visual impacts, clearance of trees and other vegetation, and disturbance to wetlands, soils and natural habitat, resulting from the greater size and number of buildings associated with the coal-fired alternatives relative to the gas-fired alternatives.

Thus, given the facility footprint and building size requirements of the coal-fired alternatives relative to the proposed project, the land use impacts of the proposed project would be preferable at the proposed site. Accordingly, the Siting Board finds that the proposed project would be preferable to the AFB, PFB, CG and PC alternatives with respect to land use impacts.

f. Solid Waste

The Company asserted that the proposed project would be preferable to the coal-fired alternatives with respect to solid waste impacts (Exh. BEL-1, at 3-19). In support of its assertion, the Company stated that the proposed project would generate minimal amounts of solid waste, approximately 35 tons per year, consisting primarily of incidental office and maintenance waste (id.). In contrast, the Company stated that the solid waste generated by the coal-fired alternatives, consisting primarily of ash or slag, would total 111,613 tpy for the CG and PC alternatives, and 372,905 for the AFB and PFB alternatives (id. at 3-19, 3-25). The Company stated that it assumed that solid waste from the coal-fired alternatives would be hauled off-site in railcars and that the ash potentially could be used as back-fill for coal mines (id. at 3-19).

The record indicates that the proposed project 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. Millennium Power Decision, EFSB 96-4 at 65; Berkshire Power Decision,

4 DOMSB at 320-321; EEC (remand) Decision, 1 DOMSB at 351-352.

Accordingly, the Siting Board finds that, for the purposes of this review, the proposed project would be preferable to the AFB, PFB, CG 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 coal-fired alternatives, the Siting Board has found that the proposed project would be preferable to the AFB, PFB, CG and PC alternatives with respect to air quality impacts, water use, noise impacts, fuel transportation impacts, land use impacts and solid waste impacts. The Siting Board has also found that the proposed project would be preferable to the AFB, PFB and PC alternatives with respect to wastewater impacts, but that the PC alternative would be preferable to the proposed project with respect to wastewater impacts. The Siting Board notes that the slight preferability of the PC alternative with respect to wastewater impacts is outweighed by the clear preferability of the proposed project with respect to all other evaluated impacts.

Accordingly, the Siting Board finds that the proposed project would be preferable to the AFB, PFB, CG and PC alternatives with respect to environmental impacts.

4. Cost

a. Description

The Company asserted that the proposed project would be superior to each of the technology alternatives considered in phase three with respect to cost (Company Brief at 51). In order to compare costs, the Company modeled the projected total revenue requirements of the proposed project and the AFB, PFB, CG and PC alternatives over both a 20- and a

30-year period beginning in January of the year 2000, the assumed in-service date of all units (Exhs. BEL-1, at 3-11 to 3-12; HO-A-6.1; HO-A-6.2). The Company stated that it then summed the NPV of annual revenue requirements and calculated 20- and 30-year nominal levelized costs in dollars per megawatt-hour ("$/MWh") for each of the alternatives

(Exh. BEL-1, at 3-11).

As noted in Section II.B.3, above, the Company indicated that the initial cost and performance data were generally taken from vendor supplied data for the proposed project and from the 1993 TAG and the U.S. Energy Administration's 1997 Annual Energy Outlook ("1997 Energy Outlook") for the technology alternatives (Exhs. BEL-1, at 3-12; HO-RR-21; HO-RR-23(S); HO-RR-23.2(red.); Tr. 2, at 54 to 59, 93 to 95). The Company stated that the 1997 Energy Outlook confirmed the ranking of the proposed project as significantly more cost effective than the technology alternatives (Exh. HO-RR-22).

With respect to fuel prices, the Company indicated that fuel price assumptions were based on the 1997 Energy Outlook (Exh. BEL-1, at 3-12; Tr. 2, at 95 to 99). The Company stated that its intent was to estimate, on a consistent basis, a year-2000 delivered fuel price specific to the New England region for each technology (Tr. 2, at 95-99). The Company indicated that it assumed that the proposed project and each alternative would run constantly, limited only by its individual equivalent availability factor (Exh. BEL-1, at 3-12, 3-21).

Table 4, below, details the total installed costs, O&M costs, and 20- and 30-year levelized cost for the alternative technologies. The Company indicated that the 20- and

30-year levelized cost of the proposed project would be significantly lower than that of the alternative technology units (id. at 3-12).

Table 4

TECHNOLOGY PARAMETERS AND LEVELIZED COSTS

	ANP Bellingham	AFB	PFB	CG	PC
Fuel	Gas	Coal	Coal	Coal	Coal
Unit Size (MW, Nominal)	545	545	545	545	545

Fuel Price ($/MMBtu)[1,2]	3.19	1.76	1.76	1.76	2.02
Equivalent Availability (percent)	92	90.4	80.8	85.7	85.5
Full Load Heat Rate (Btu/kWh)	6,700	9,796	8,959	8,090	9,618
Total Plant Investment[3] ($/kW)	*	1,737	1,517	1,971	1,759
Fixed O&M ($/kW-yr)[2,4]	*	84.79	87.70	105.84	107.43
Variable O&M ($/kWh)[2]	*	6.64	4.06	0.61	2.80
20-Yr Nominal Levelized Cost ($/kWh)	*	.0733	.0716	.0717	.0779
30-Yr Nominal Levelized Cost ($/kWh)	*	.0748	.0711	.0728	.0795

1. Year-2000 fuel prices for gas-fired units are based on 100 percent load factor.

2. First year cost based on in-service date of January 1, 2000.

3. Based on in-service date of January 1, 2000.

2. Total Plant Investment includes total cost of plant, administration & general costs, property taxes and insurance.

---

* Total plant investment, fixed O&M, variable O&M, 20-year nominal levelized cost and 30-year nominal levelized cost for the proposed project were less than the corresponding values for each of the other considered alternatives

(Exhs. HO-A6.1-C (conf.); HO-A6.2-C (conf.)).

Sources: Exhs. BEL-1, at 3-21, 3-23; HO-A-6.1; HO-A-6.2.

b. Analysis

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

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

5. Reliability

a. Description

The Company asserted that the proposed project would be preferable to each of the technology alternatives with respect to reliability (Exh. BEL-1, at 3-20). In analyzing the reliability of the proposed project and the technology alternatives, the Company assessed

(1) the anticipated availability of each technology and corresponding energy source, and

(2) the likelihood that the technology would be available at the time for which the first need for new capacity has been identified (id. at 3-19 to 3-20).

The Company stated that projects that rely on a mature, commercially available technology have a reliability advantage over technologies whose expected cost and performance characteristics have yet to be fully demonstrated and are based primarily on engineering estimates (id.). The Company indicated that the proposed project and the PC alternative use technologies classified as mature in the 1993 TAG and would therefore have a reliability advantage over the AFB technology, classified as commercial, and the PFB and CG technologies, classified as demonstration level technologies (id.). The Company indicated that the anticipated availability of the proposed project, 92 percent, surpassed the anticipated availability of the other technology alternatives (see Table 4, above) (id. at 3-19). With respect to the likely high availability of the proposed project, the Company also emphasized the proposed project's limited overhaul maintenance requirements and readily available replacement parts (id.). In addition, the Company anticipates a firm gas supply for the proposed project (Tr. 3, at 147) (see Section II.C.3.b, below).

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. The Company has also indicated that the proposed project likely would have a firm gas supply (see Section II.C.3.b, below).

In comparing the reliability of the proposed project to that of the alternatives, all of which are coal-fired, the Siting Board first notes that the record in this case is inconclusive with regard to differences in the reliability of a natural gas supply delivered via pipeline and a coal supply delivered via rail.

In comparing the reliability of the proposed project to the reliability of the AFB alternative, the Siting Board notes that the availability factor for the AFB alternative is assumed to be 90.4 percent, 1.6 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 AFB alternative, does not represent a significant difference for the purposes of this review. The proposed project, however, is classified as a mature technology, denoting significant operating experience, while the AFB alternative is classified as a commercial technology, denoting limited operating experience. Accordingly, the Siting Board finds that the proposed project would be preferable to the AFB alternative with respect to reliability.

In comparing the reliability of the proposed project to the reliability of the PFB alternative, the Siting Board notes that the availability factor for the PFB alternative is assumed to be 80.8 percent, 11.2 percent less than that of the proposed project, indicating the somewhat greater availability of the proposed project. In addition, the proposed project is classified as a mature technology, denoting significant operating experience, while the PFB alternative is classified as a demonstration technology. The CG alternative, with an availability factor of 85.7 percent, fares better than the PFB alternative when compared to the proposed project, but it, too, is classified as a demonstration technology, i.e., some limited operating experience exists but the technology requires further research and development to qualify as commercial or mature. Accordingly, the Siting Board finds that the proposed project would be preferable to the PFB and CG alternatives 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 PC alternative and preferable to the AFB, PFB and CG 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 alternative approaches in its ability to address the previously identified need in terms of environmental impact, cost, and reliability.

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

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

C. Project Viability

1. Standard of Review

a. Existing Standard

The Siting Board determines that a proposed NUG is likely to be a viable source of energy if (1) the project is reasonably likely to be financed and constructed so that the project will actually go into service as planned, and (2) the project is likely to operate and be a reliable, least-cost source of energy over the planned life of the proposed project. Millennium Power Decision, EFSB 96-4, at 71; Dighton Power Decision, EFSB 96-3, at 24; Berkshire Power Decision, 4 DOMSB at 346.

In order to meet the first test of viability, the proponent must establish (1) that the project is financiable, and (2) that the project is likely to be constructed within the applicable time frame and will be capable of meeting performance objectives. In order to meet the second test of viability, the proponent must establish (1) that the project is likely to be operated and maintained in a manner consistent with appropriate performance objectives,

and (2) that the proponent's fuel acquisition strategy reasonably ensures low-cost, reliable energy resources over the planned life of the proposed project. Millennium Power Decision, 96-4, at 72; Dighton Power Decision, EFSB 96-3, at 24; Berkshire Power Decision, 4 DOMSB at 345.

2. Financiability and Construction

a. Financiability

In considering a proponent's strategy for financing a proposed project, the Siting Board considers whether a project is reasonably likely to be financed so that the project will actually go into service as planned. The Company asserted that the Siting Board should consider the proponent's access to financial resources as well as the competitiveness of a proposed project in the deregulated market in order to assess the financiability of a proposed merchant plant (Exh. BEL-1, at 4-2).

ANP stated that it had budgeted funds necessary to finance the development of the proposed project as well as two additional merchant facilities proposed for Massachusetts and Maine (Exh. HO-V-10). ANP Bellingham stated that its parent American National Power would use cash flow from ongoing operations to fund development of the proposed project (Exh. BEL-1, at 4-2). ANP stated that National Power ("NP") would provide 100 percent equity funds during the construction period and possibly throughout the operating period, depending on the cost of debt (id.). The Company stated that it expected that any funds borrowed by NP to fund the project would be borrowed on the balance sheet at a cost of debt below that which would be available under project financing (Exh. BEL-1, at 4-2 to 4-3). The Company asserted that the use of equity funds would lower costs and provide other viability advantages such as the elimination of the restrictions often attached to debt funding and elimination of any external milestones precedent to project financing (id.).

The Company indicated that American National Power, the United States development and operating affiliate of NP, has an ownership share totalling 678 MW in 1,536 MW of generating capacity in the United States and that NP has investments in and/or operates approximately 24,100 MW of generating capacity throughout the world (id. at 4-3). Further, the Company asserted that NP is one of the financially strongest generating companies in the world, with 10.2 billion dollars of market capitalization, and therefore has the capability to finance the one-half billion dollars required for the Blackstone and Bellingham facilities (id.; Tr. 3, at 107). Mr. Pedrick added that, since privatization, NP has invested more than

1.5 billion dollars in the United Kingdom and over a billion dollars in other international projects (Tr. 3, at 108).

To demonstrate the financial viability of the proposed project, the Company provided nine pro forma analyses showing the internal rate of return ("IRR") under base, high and low case dispatch factors and base, high and low case revenue assumptions (Exh. V-14 (conf);

Tr. 3, at 83-84). Mr. Haupt stated that: (1) the base case dispatch factor was 90 percent;

(2) the base case revenue assumption was consistent with assumptions used in the economic efficiency analysis; and (3) fuel costs, constant in all pro formas, were determined from a study commissioned by the Company (Tr. 3, at 84, 88-89). He stated that the high and low dispatch cases were a five percent increase and decrease, respectively, of the base case and that the high and low revenue cases were a ten percent increase and decrease, respectively of the base case (Tr. 3, at 84). He stated that each pro forma analysis, with the exception of the analysis that combines the low case dispatch factor with the low case revenue assumptions, shows an IRR that would be acceptable to the Company (id. at 84-85). In addition, he argued that IRRs under low case revenue conditions likely would be higher than what is projected in the pro formas because gas costs likely would be lower than assumed in a low-revenue market (id. at 90). He also indicated that the pro formas reflect the fact that debt would be incurred by NP and not by the proposed project (id. 86-87).

The Company indicated that this is the first plant that would be built by ANP exclusively as a merchant plant and that the power would be marketed by ANP Bellingham Energy Company (id. at 64-65). The Company stated that it is attempting to develop a fleet of assets in New England and that each generating facility would be bid into the pool, considering the other generating facilities owned by the Company (id. at 66). The Company estimated that the proposed facility likely would run 90 percent of the time it is available due to its low cost (id. at 67). The Company stated that power would be sold through the pool by bidding into the pool an amount equal to the project's cost or an amount slightly above its variable costs, but lower than the market-clearing price (id.). ANP stated that power also could be sold through bilateral agreements if the negotiated price was higher than the pool price, but noted that its economic assessment shows financial viability assuming pool prices (Tr. 3, at 111-112). ANP added that its economic efficiency analysis also demonstrates the proposed project's competitiveness in the deregulated market (Exh. BEL-1, at 4-1).

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

NP has committed to finance the proposed project internally. The record indicates that NP has a broad range of experience in the overall project development process, including financing, and has developed numerous generating facilities worldwide. NP also has substantial capital resources for equity investment in power projects.

The range of assumptions provided by the Company in its pro formas is generally reasonable and consistent with Siting Board reviews in prior proceedings. The

Company's pro formas indicate that the proposed project would provide a favorable IRR under differing levels of dispatch and revenue.

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

b. Construction

In considering a proponent's strategy for a proposed project, the Siting Board considers whether the project is reasonably likely to be constructed and go into service as planned. Millennium Power Decision, EFSB 96-4, at 79; Berkshire Power Decision,

4 DOMSB at 332. ANP stated that, with NP, it has developed and constructed several combined cycle power plants totaling over 4,000 MW over the past ten years, (Exh. BEL-1, at 4-4). ANP added that the majority of the combined cycle facilities owned or operated by ANP and NP have been constructed under turnkey EPC contracts where the contractor was also the equipment vendor (id.).

Here, the Company indicated that it is currently negotiating an EPC contract with ABB (id. at 4-5). The Company stated that since 1939, ABB has supplied or has under construction over 1,000 gas turbines in 470 power stations worldwide, including more than 125 combined cycle plants, of which approximately 50 percent were supplied on a turnkey basis (id. at 1-4). ANP stated that ABB will design and construct the plant to achieve a

20.5- month construction schedule (id. at 4-5). In addition, ANP stated that ABB has agreed to guaranteed heat rate, output, and schedule terms with liquidated damages on a "keep-whole" basis such that the viability of the proposed project would not be jeopardized if any of the guarantees were not met (id.; Tr. 3, at 94-96). ANP stated that ABB also has agreed to a guaranteed availability with a significant penalty if availability terms are not met (Tr. 3,

at 95-96).

The Company stated that the EPC contract will provide the owner with a fixed price for the proposed project based on an agreed scope of work (id. at 100). The Company stated that ABB will be responsible for all design, engineering, procurement, delivery, construction tasks, installation and training needed to bring the plant into operation at guaranteed output, heat rate, emissions, noise and other performance levels (id. at 100-101). The Company explained that the EPC contract will include provisions for: (1) a fixed price with payments on a milestone basis; (2) a guaranteed schedule; (3) liquidated damages for failure to achieve (a) substantial completion by the guaranteed completion date, or (b) operation guarantees;

(4) bonuses for early completion and improved performance; and (5) insurance (id.

at 100-103). The Company noted that a minimum availability of 92 percent is projected for the life of the proposed project (id. at 64-65).

The Company indicated that the ABB GT24/26 is a relatively new combustion turbine developed by ABB over the last several years (id. at 53). ANP stated that there are currently four ABB GT24/26 turbines operating worldwide in the single-cycle mode, and a number of other ABB GT 24/26 turbines under construction or under contract (id. at 53-55). Mr. Haupt stated that ANP/NP has a history of using new, state-of-the-art combustion turbine technology which it considers to be the most competitive technology in the field (id.

at 56-57). Mr. Pedrick stated that due to the Company's background in owning and operating generating facilities, it is able to work with combustion turbine manufacturers to determine the technical risks that prevail and to work with them to ensure that the plants will be safely constructed and operated (id. at 57). Mr. Haupt added that although there is a higher degree of risk associated with a newer technology, aggressive guarantees from ABB with respect to heat rate, output and availability will mitigate those risks to the Company (id. at 59).

The Company indicated that none of ANP/NP's existing facilities use steam augmentation and that it is not aware if any of the ABB GT24/26 units in progress will use this technology (id. at 61-62). However, the Company maintained that ABB is familiar with steam augmentation technology and that the technology involves no specific technical risks other than a slight increase in the complexity of the machine and an increase in the commissioning period at the end of construction (id. at 62-63).

In addition, the Company indicated that it has experience in developing more than one facility of this size and type in the same time frame (Exh. HO-V-17). In addition to the Bellingham and Blackstone units, ANP stated that it is currently developing two merchant facilities in Maine and Texas, and that NP is currently developing a number of projects worldwide (id.).

The Company stated that the proposed project would be interconnected with the regional electric transmission grid via a short tie line to the existing NEPCo 303 transmission line, which operates at 345 kV and which is located on a 325-foot wide ROW that traverses the eastern portion of the site (Exh. BEL-1, at 6-22). ANP provided a draft system impact study which details the impacts to the NEPCo and BECo transmission systems of interconnecting both the proposed facility and the proposed Blackstone facility to the transmission grid, and which identifies system-wide upgrades that will be required for interconnection (Exh. HO-EE-14.1). These system wide upgrades include the reconductoring of the NEPCo 303 transmission line between the proposed facility and the West Medway substation to the north, reconductoring of additional transmission lines, and upgrades to terminal equipment at a number of substations (Exh. HO-EE-14.1, at 23-24). The Company added that it has been notified by NEPCo that the reliability of the 303 circuit has historically been better than the 345 kV system average (Exh. HO-V-38.1).

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. Millennium Power Decision, EFSB 96-4, at 82; Dighton Power Decision, EFSB 96-3, at 26-27; Altresco-Pittsfield Decision, 17 DOMSC at 380.

Here, the Company has not submitted a draft or final EPC contract. However, the record in this proceeding indicates that the Company and ABB have significant experience in the design and construction of generation plants which use technology similar to that proposed for this project and have successfully completed comparable projects. The Siting Board accepts that the Company's experience in negotiating EPC contracts for comparable projects contributes strongly to its ability to negotiate an acceptable final EPC contract. It also notes that the Company has stressed its intentions to provide low cost, clean power and has stated that its construction practices are structured to fulfill these objectives. However, in the absence of a final EPC contract between ANP and ABB, the record contains no assurance that ABB actually will be the EPC contractor for this project. Therefore, the Siting Board requires the Company to provide the Siting Board with a copy of a signed EPC contract between ANP and ABB, or a comparable entity, that contains provisions that provide reasonable assurance that the project would perform as a low cost, clean power producer.

The Siting Board notes that while an interconnection study has been prepared, the Company has not entered into a signed interconnection agreement with NEPCo enabling transmission access. Failure to negotiate a final interconnection agreement acceptable to both parties would prevent the proposed project from providing energy to the Commonwealth and the region. See Millennium Power Decision, EFSB 96-4, at 82-83; Berkshire Power Decision, 4 DOMSB at 336. However, if the Company provides a signed interconnection agreement, it will be able to establish that its proposed project is likely to be capable of being dispatched as expected. Therefore, the Siting Board requires the Company to provide the Siting Board with a copy of a signed interconnection agreement between the Company and NEPCo.

Finally, the Siting Board notes that the proposed ABB GT24/26 turbine has commercial operating experience in the single cycle rather than combined cycle mode. While the record indicates that ABB would be responsible for correcting any problems with the turbine, the proposed project cannot go forward as planned if there are unexpected delays in turbine development or testing. The Siting Board reiterates that a project proponent has an absolute obligation to construct and operate its facility in conformance with all aspects of its proposal (see Section IV, below). Should the ABB GT24 turbine be unable to perform substantially as expected, ANP would be required to notify the Siting Board as explained in Section IV, below.

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

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

3. <u>Operations and Fuel Acquisition</u>

a. <u>Operations</u>

In determining whether a proposed NUG project is likely to be viable as a reliable, least-cost source of energy over the planned life of the proposed project, the Siting Board evaluates the ability of the project proponent or other entities to operate and maintain the facility in a manner which ensures a reliable energy supply. <u>Millennium Power Decision</u>, EFSB 96-4, at 84; <u>Dighton Power Decision</u>, EFSB 96-3 at 27; <u>Altresco-Pittsfield Decision</u>, 17 DOMSC at 381-382. In a case where the proponent has relatively little experience in the development and operation of a major energy facility, that proponent has been asked to establish that experienced and competent entities are contracted for, or otherwise committed to, the performance of critical tasks. These tasks have historically been enumerated in detailed contracts or other agreements that include financial incentives and/or penalties which ensure reliable performance over the life of the facility. <u>Millennium Power Decision</u>, EFSB 96-4, at 84; <u>Berkshire Power</u>, 4 DOMSB at 337-339; <u>Altresco-Pittsfield Decision</u>,

17 DOMSC at 382-383.

ANP stated that the proposed project would be competitively priced, new, efficient and clean (Exh. BEL-1, at 1-1). ANP asserted that its experience owning and operating combined cycle plants over the last decade (including its recent experience owning and operating the Milford Power plant), NP's technical resources and ANP's intention to operate the facility, ensure that the proposed project will be operated reliably and cost-effectively to compete in the deregulated electric market (<u>id.</u> at 4-11). Mr. Haupt stated that ANP Operating Company, a company 100 percent owned by ANP, will operate the proposed facility (Tr. 3, at 114-115). He further stated that ANP Operating Company currently operates the Milford Power facility and is expected to operate all of ANP's merchant plants (<u>id.</u>). He added that a contract would be signed with ANP Operating Company during the construction period because operations personnel will be hired at that time to help facilitate the construction of the proposed facility (<u>id.</u> at 114). The

Company stated that NP owns and operates generating facilities totaling 17,000 MW in the United Kingdom (id. at 115-116).

ANP provided a summary of its O&M program (Exh. BEL-1, at 4-6 to 4-11). ANP stated that its O&M program will include procedures for: (1) normal plant O&M functions; (2) catastrophic avoidance; (3) emergency preparedness; (4) incremental improvement in the condition and capability of the facility; and (5) equipment status monitoring and documentation (id. at 4-6). The Company stated that, during operation, the facility would be maintained in optimal condition using proactive, predictive and preventive maintenance techniques to minimize disruptions to production and downtime (id. at 4-9).

In past cases, the Siting Board has found that an acceptable, executed O&M contract with an appropriate, experienced entity provided sufficient assurance that a project is likely to be operated and maintained in a manner consistent with reliable performance objectives. Millennium Power Decision, EFSB 96-4, at 85; Dighton Power Decision, EFSB 96-3, at 28; Altresco-Pittsfield Decision, 17 DOMSC at 382. However, provision of such a contract is required only "[i]n a case where the proponent has relatively little experience in the development and operation of a major energy facility...". Millennium Power Decision, EFSB 96-4, at 84; Berkshire Power Decision, 4 DOMSB at 337-339; Altresco-Pittsfield Decision, 17 DOMSC at 382-383. ANP has demonstrated that it has considerable experience operating major energy facilities both in Massachusetts and in other states and countries, and has indicated that it intends to operate the proposed facility through its wholly-owned subsidiary, ANP Operating Company. Further, ANP has provided a summary of its anticipated O&M plan, which provides reasonable assurance that the project would perform as a low-cost, clean power producer. Accordingly, the Siting Board finds that the Company has established that the proposed project is likely to be operated and maintained in a manner consistent with appropriate performance objectives.

The Board's conclusions regarding the Company's O&M assume that the final contract between ANP and ANP Operating Company will be consistent with the O&M plan outlined during the proceedings. In Section IV, below, the Siting Board requires ANP to notify the Siting Board of any changes other than minor variations to the proposal so that the Siting Board may decide whether to inquire further into that issue. Therefore, if the terms of the O&M contract differ significantly from the O&M plan considered in this analysis, the Company shall describe the changes and explain how such changes would affect the Company's objectives to provide low-cost, clean power.

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 planned life of the proposed project.

ANP stated that gas supply strategies should be as flexible as possible in a merchant plant environment (Tr. 3, at 152). The Company asserted that its gas supply strategy would ensure the delivery of natural gas to the proposed project on a reliable basis at a low price that would reflect competitive prices in the market and supply areas (Exh. BEL-1, at 4-16). ANP indicated that it plans to connect to the Algonquin Gas Transmission Company ("AGT" or "Algonquin") pipeline located approximately one mile to the north of the site, and that AGT has initiated proceedings for construction of the connecting pipeline with the Federal Energy Regulatory Commission ("FERC") (Exh. BEL-1, at 1-13; Tr. 3, at 144). ANP indicated that although it does not currently plan to physically interconnect the proposed project with the Tennessee Gas Pipeline Company ("TGP"), it may enter into an exchange agreement with TGP and AGT whereby it could contract with both pipelines through either one renting space to the other (Tr. 3, at 145).

The Company stated that it anticipates a firm gas supply for the proposed project (id. at 147). ANP stated that it is considering three general categories of supply arrangements including: (1) firm supplies that are delivered by a supplier directly to the plant meter; (2) firm supplies that are delivered to a liquid point of receipt on the TGP or AGT system by a supplier with firm transportation from that point to the proposed facility; and (3) a supply from the east or north of the site that would be received through displacement (id. at 147-148, 152-153). The Company indicated that it issued a Request for Proposals ("RFP") for a 365-day gas supply for the proposed Bellingham facility and two additional generating facilities proposed by ANP in Blackstone, Massachusetts and Gorham, Maine (id., at 151-152, 157-158). Mr. Kasle stated that the offers from suppliers in response to the RFP were well in excess of the gas supply requirements for the three proposed facilities (id. at 159). The Company stated that the suppliers who responded to the RFP were equally reliable and that the responses therefore would be evaluated on the basis of flexibility of the supply arrangements and pricing (id. at 153). ANP stated that it anticipated gas supply contracts of varying lengths, but generally three to five years with evergreen provisions (id. at 161-162). In addition ANP stated that it would consider an arrangement whereby the electricity buyer would provide gas for the project (id. at 154-155).

The Company stated that it had initiated negotiations with potential suppliers and that a gas supply would be in place for the proposed facility prior to the commencement of construction (id. at 151). The Company stated that it was certain that the supplies offered in the RFP would still be available at the time the contracts are signed (id. at 167). The Company explained that the suppliers who responded were large players in the industry who buy their gas from a number of sources (id.). In addition, the Company explained that such factors as its internal financing and progress in project development make ANP a good market from a supplier's point of view and that it therefore did not anticipate that supply offers would be withdrawn in favor of competing generating facilities (id. at 167-168).

The Company indicated that firm transportation would be arranged by the supplier to the facility or by ANP back to a liquid point of receipt (id. at 148). The Company stated that it has been discussing transportation from liquid points of receipt with both TGP and AGT (id. at 149). The Company noted that if supplies were obtained from the north or east of the site via displacement, firm transportation would not be necessary to ensure reliability (id.

at 149-150). The Company stated that its fuel supply arrangement for firm supply and transportation would enable the proposed facility to operate without fuel oil backup (id.

at 151-152).

The Company indicated that it has gained experience in contracting for similar gas supply and transportation arrangements for its Milford Power facility (Exhs. HO-V-19;

HO-V-31). In addition, Mr. Kasle, who is responsible for developing the fuel strategy, sourcing fuel supplies and transportation and negotiating contracts, indicated that he had twelve years of energy-related experience, including experience in buying and selling natural gas and transportation on a short and long term basis, and in developing fuel supply strategies for greenfield power projects (Exh. BEL-6). Further, Mr. Mitchell, who has been assisting the Company in developing a gas purchase and transportation strategy, stated that he had extensive experience in gas supply and transportation strategy and procurement, including evaluating gas supply and transportation economics, regulations, rates, supply options, and negotiating contracts (Exh. BEL-7).

In considering an applicant's fuel acquisition strategy, the Siting Board considers whether such a strategy reasonably ensures a low-cost, reliable source of energy over the planned life of the proposed project. Millennium Power Decision, EFSB 96-4, at 90; Dighton Power Decision, EFSB 96-3, at 28; Berkshire Power Decision, 4 DOMSB at 343. The Siting Board has recognized that, in considering a petitioner's fuel acquisition strategy, it is appropriate to consider the need for flexibility, the expected shorter time frame of PPAs in a restructured electric industry, and the industry-wide shift away from long-term gas supply contracts. Millennium Power Decision, EFSB 96-4, at 90; Dighton Power Decision, EFSB 96-3, at 28; Berkshire Power Decision, 4 DOMSB at 343. Nevertheless, the Siting Board must still be convinced that a low-cost, reliable fuel supply will be available to a proposed project in order to determine that a proposed project will be capable of providing a necessary energy supply consistent with its mandate.

In past decisions, the Siting Board generally has reviewed final fuel transportation and/or supply contracts between proponents and pipeline companies. While the Siting Board has not required proponents to submit signed long-term fuel supply contracts in recent cases, it generally still has required firm transportation contracts from a major interconnection point as assurance that a proponent's gas supply strategy is viable.

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

Here, the Company has presented a fuel acquisition strategy that involves the intent to contract for a 365 day firm natural gas supply that would be: (1) delivered to the proposed facility meter by the supplier; (2) delivered to an interconnection point in the region by the supplier with a firm transportation agreement from the point to the proposed facility; or (3) delivered to the proposed facility via displacement if the supplies are obtained from areas to the north or east of the proposed facility. The Company noted that firm transportation would not be required if the gas was delivered via displacement. The Company has issued an RFP for gas supply and has received offers well in excess of the requirements of the proposed facility and has entered into negotiations for firm transportation arrangements with both AGT and TGP. The Company plans to have its gas supply contracts in place prior to the start of construction. In addition, the Company has demonstrated that it has experience in procuring fuel for comparable facilities including a facility in Massachusetts.

It is likely that the fuel supplies selected by the Company will be low cost, due to its ability to take advantage of a variety of gas suppliers and transportation options. In addition, each of the three transportation options being considered by the Company, alone or in combination, would provide assurance that supplies would be delivered to the proposed project on a firm basis. Accordingly, the Siting Board finds that the Company has established that its fuel acquisition strategy reasonably ensures a low-cost, reliable source of energy over the planned life of the proposed project.

However, the Company has not yet entered into contracts for gas supply and transportation. The Siting Board's conclusions regarding the Company's fuel acquisition strategy assume that the final contracts will be consistent with one of the fuel supply and transportation options outlined during this proceeding. In Section IV, below, the Siting Board requires ANP to notify the Siting Board of any changes other than minor variations to the proposal so that the Siting Board may decide whether to inquire further into that issue. Therefore, the Company shall notify the Siting Board if contracts are executed that provide for fuel transportation arrangements other than those considered in this analysis, and submit to the Siting Board a discussion of the changed transportation arrangements and explain how such arrangements would affect the cost and reliability of the project's gas supply.

The Siting Board has found that the Company has established that (1) the proposed project is likely to be operated and maintained in a manner consistent with appropriate performance objectives, and (2) its fuel acquisition strategy reasonably ensures a low-cost, reliable source of energy over the planned life of the proposed project. Accordingly, the Siting Board finds that the Company has established that its proposed project meets the Siting Board’s second test of viability.

4. Findings and Conclusions on Project Viability

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

Accordingly, the Siting Board finds that, upon compliance with the aforementioned conditions, ANP 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. Millennium Power Decision, EFSB 96-4 at 94; Dighton Power Decision, EFSB 96-3 at 31; Berkshire Power Decision, 4 DOMSB at 347.

1. Standard of Review

In order to determine whether a facility proponent has shown that siting plans for its proposed project are superior to alternatives, the Siting Board requires a facility proponent to demonstrate that it examined a reasonable range of practical facility siting alternatives. Millennium Power Decision, EFSB 96-4 at 94; Dighton Power Decision, EFSB 96-3 at 31; Berkshire Power Decision, 4 DOMSB at 347.

To determine that a facility proponent has considered a reasonable range of practical facility siting alternatives, the Siting Board has previously required the proponent to satisfy a two-pronged test. The proponent has had, first, to 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. Millennium Power Decision, EFSB 96-4 at 94; Dighton Power Decision,

EFSB 96-3 at 31; Berkshire Power Decision, 4 DOMSB at 347. Second, the proponent has had to establish that it identified at least two noticed sites or routes with some measure of geographic diversity. Millennium Power Decision, EFSB 96-4 at 94-95;

Dighton Power Decision, EFSB 96-3 at 32; Berkshire Power Decision, 4 DOMSB at 347-348.

As indicated in Section I.D, above, the Siting Board allowed ANP to withdraw its alternate site from Siting Board consideration. The second part of this test therefore was adapted to the review of a petition with only one noticed site. Specifically, ANP must show that it has examined a reasonable range of practical facility siting alternatives by:

(1) establishing 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 proposed site, and (2) identifying at least two potential facility sites with some measure of geographic diversity. This adapted standard of review helps to ensure that the proposed facility is sited so as to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

2. Development and Application of Siting Criteria

The Company indicated that its initial site selection process was designed to:

(1) identify a reasonable universe of site alternatives; (2) apply a consistent set of objective site evaluation criteria; and (3) select from the identified universe of site alternatives a site which minimizes cost and environmental impacts while ensuring supply reliability

(Exh. BEL-1, at 5-2).

a. Description

The Company stated that it narrowed its site search to the Commonwealth of Massachusetts for the following reasons: (1) Massachusetts' location within the area proximate to most significant load centers in the region; (2) regulatory preference in Massachusetts for least-cost, least environmental impact generating facilities; and (3) the Commonwealth's spearheading of electric industry restructuring and the resulting favorable market environment for merchant plants (id. at 5-3).

The Company indicated that its site selection process initially focused on locations proximate to major natural gas transmission pipelines and electric transmission systems throughout Massachusetts (id. at 5-2). The Company stated that it identified two significant node locations, and that it concentrated its site selection search along "corridors" in the area of these identified node locations, one in the Merrimack/Concord River Valley ("northern node") and the second in the Blackstone River Valley ("southern node") (id.). The Company indicated that it defined the corridors used in its site selection process as the area along the northern and southern nodes with direct access to electric transmission and within one mile of the interstate gas pipeline system (id. at 5-3 to 5-4). The Company indicated that it reviewed areas within each corridor to identify potentially available parcels that met a set of minimum threshold criteria, but noted that it subsequently narrowed its search to sites in the southern node on the basis of electric transmission issues (id. at 5-2).

The Company stated that contacts to gauge receptivity with towns and with landowners proceeded in tandem with the site evaluation process. The Company indicated that in some instances, a contacted municipality identified particular sites not necessarily within the defined site selection corridor and that, if appropriate, these municipality-identified sites were included for assessment and were eliminated or carried forward for review on the same basis as other sites (id. at 5-5).

The Company established a series of threshold criteria by which it evaluated potential sites identified using the "corridor approach" described above (id. at 5-4). These criteria were: the site must be vacant; the site must have no mapped endangered species habitat; the site must have a parcel size of at least 25 acres, with at least 10 acres of "buildable" land (defined as no indicated wetlands or excessive slopes); and the site and interconnects must be located within a single community (id.). The Company conducted its evaluation first on the basis of United States Geological Survey ("USGS") and geographic information systems ("GIS") mapping; second, with the aid of community zoning and tax maps; and third, via site reconnaissance ("ground truthing") (id. at 5-5). The Company stated that following the completion of ground truthing, 17 sites in the southern node were carried forward for further evaluation (id.).

The Company stated that sites which met its minimum threshold criteria were then assessed against a set of 20 site screening criteria: (1) ease of electrical interconnection;

(2) ease of gas interconnection; (3) site size/buffering potential; (4) site topography and geology; (5) potential for site contamination; (6) water availability; (7) wastewater disposal availability; (8) adequacy of roadway/rail infrastructure; (9) dispersion environment;

(10) proximity to airports; (11) surface water resources; (12) groundwater resources;

(13) proximity to wetland/floodplain resources; (14) endangered species/significant habitat; (15) land use compatibility; (16) compatibility with zoning/community development designation;

(17) proximity to sensitive receptors; (18) potential for compliance with local or state noise regulations; (19) project visibility and compatibility with existing viewshed; and (20) level of community support (id.).

To derive an overall suitability score, weighting factors (on a 1-10 scale, with 10 indicating criteria of greatest importance) were developed for each criterion based on the project team's judgment of the relative importance of each criterion in terms of overall site suitability (id. at 5-6 to 5-15). The Company then evaluated each potential site by assigning suitability ratings of high (two points), medium (one point) or low (zero points) for each criterion (id. at 5-15). The Company derived an overall site suitability score for each of the 17 sites in the southern node by totalling the individual weighted scores for each of the 20 screening criteria (id.).

The Company stated that six sites emerged in the top scoring group based on its evaluation process (id.). The Company indicated that it eliminated its top-ranked site after learning from the owner that the site was under consideration for sale for residential development and that the owner was unwilling to enter into an option agreement (id.). The Company stated that each of the five remaining sites was further evaluated based on detailed discussions with community officials and landowners (id.). The Company stated that, based on its investigations, the proposed site was confirmed as a viable site, and that strong site attributes and serious community support presented persuasive reasons to pursue the site further (id. at 5-16). The Company pointed out that others of the top scoring sites presented significant development potential, and were of interest to the Company with respect to a second contemplated generation project (id.).

The Company asserted that it did not use, and would not advocate using, numerical scoring alone to select its preferred site. The Company's witness argued that site selection was best approached as a bifurcated process, with a short list produced based on a numerical system and a final determination of rank based on the experience and judgment of the Company and its consultants (Tr. 6, at 34 to 35).

The three active intervenors in the instant proceeding, the Town of Franklin, the Bellingham Conservation Commission and local resident Joseph Goulart, argued that the Company's application of its site selection protocol was flawed, and that there were other sites among the Company's top scoring group, including a second site in Bellingham known as "Bellingham 4", which were superior to the Company's proposed site for the project (Town of Franklin Brief at 10 to 17; BCC Brief at 2 to 3; Joseph Goulart Brief at 2 to 6).

The Town of Franklin and Mr. Goulart suggested their own different weighting and suitability ratings for the Company's screening criteria; these ratings would result in a change in the rankings within the highest-ranked group of sites, and specifically, a lowering of the ranking of the proposed site (Town of Franklin Brief at 11 to 16; Goulart Brief at 2 to 5). In addition, Mr. Goulart argued, first, that the Company emphasized economic considerations over environmental factors, and, second, that the Company applied its criteria inconsistently to the 17 sites evaluated in the southern node, especially with respect to community support, noise and gas interconnection impacts, and land use compatibility (Goulart Brief at 2 to 6). With respect to land use compatibility, Mr. Goulart argued that the question of compatible land use is not a function of zoning, and asserted that the Company scored sites at least in part on the basis of zoning rather than on the basis of the rankings for the land use criterion as defined.

The Bellingham Conservation Commission contended that the Company applied its site selection criteria inconsistently for the evaluated sites with regard to potential noise impacts of the proposed project, location of the proposed project relative to groundwater resources, and potential impacts of interconnecting the proposed project to a natural gas pipeline (BCC Brief at 2 to 3).

The Town of Franklin argued that, because the Company failed to consider the position of residents of Franklin in evaluating community support, the criterion "community support" measured support for "obtaining the necessary permits, waivers and contracts from the Town of Bellingham, rather than ... true community support" (Town of Franklin Brief at 16). In addition, the Town of Franklin argued that the Company "knowingly used incorrect data to further its own pecuniary interest" in scoring the sites considered in its site selection process and "has made no effort to correct the scores that it is relying on to establish the superiority of the Proposed Site" (id. at 17). The Town of Franklin also contended that in the Company's view the basic differences between the proposed Bellingham site and the second-highest scored Bellingham site are not environmental, but related to zoning designation and the preference of the Town of Bellingham, and that this perspective undervalued important environmental differences between the two sites (id.).

b. Analysis

In this case, the Siting Board uses a modified scope for reviewing a generation facility applicant's process to select a site for its proposed facility, waiving the requirement that applicants identify two or more sites to be noticed for purposes of the review. Under the modified scope, the Siting Board's review focuses on the selection of a single noticed site from top-ranked sites, including sites in the last stage of the Company's site selection process, as well as on sites which ranked high among the Company's second tier of sites.

While the Company was not required to identify and notice a preferred and alternative site for its proposed facility, the Siting Board's precedent with respect to the development and application of site selection criteria for generating facilities remains applicable. Here, the Company has developed a broad array of criteria which address the critical issues associated with the siting of generating facilities and which are generally consistent with site selection criteria which the Siting Board has found to be appropriate in previous reviews. Millennium Power Decision, EFSB 96-4, at 101; Berkshire Power Decision, 4 DOMSB at 349-351; Cabot Decision, 2 DOMSB at 380-381.

The intervenors have questioned whether the Company applied its site selection criteria consistently to the proposed site and to other sites in its site selection process, including a second Bellingham site, Bellingham 4. The intervenors' concerns focus specifically on the rating of the proposed site and Bellingham 4 with respect to water availability, gas interconnect impacts, land use compatibility and community support.

With respect to ranking of the proposed site above other sites based on on-site water availability, the proposed project as now designed will draw its water supply from the local municipal water system. Viewed in the context of the current design, this criterion is unlikely to distinguish the proposed site from most considered sites, including sites in the Town of Bellingham.

The Siting Board agrees that on-site water availability represents a reasonable factor to include at the screening level, when the water supply requirements and water supply sources of the proposed project might be generally but not finally determined. However, the availability of water from various sources, including public water supplies, wastewater reuse and direct withdrawals from wells or other sources, should be reflected in a Company's water availability criteria. The importance of on-site water availability likely was overstated in the Company's analysis. By way of counterweight, however, the Siting Board notes that other water-resource related criteria, in particular the "proximity to groundwater resources" and "proximity to wetland/floodplain resources" criteria, serve to disadvantage the proposed site relative to some other top-ranked sites, including the Bellingham 4 site, and are given substantial weight. These criteria may also be overstated since the proposed facility footprint can be placed to minimize or avoid groundwater and wetland/floodplain resources.

With respect to gas interconnect impacts, the Company assigns its proposed site a medium rating, although the one-mile proposed gas interconnect slightly exceeds the threshold which would seemingly qualify the site for a low rating on this criterion. As an additional factor supporting a lower rating, there is the possibility that an open-trench crossing of the Charles River, with attendant impacts to the river and adjacent wetlands, could be necessary to construct a gas interconnect to the proposed site. While the Company has indicated its commitment to directional drilling for the river crossing, the final decision as to how the gas interconnect to the proposed site would be installed across the Charles River rests with the company installing the gas pipeline and with FERC (see Section III.B.2.b).

With respect to land use, the Siting Board notes that the Company's site selection process includes separate criteria for land use compatibility and compatibility with zoning, with land use compatibility given more weight than compatibility with zoning. With respect to site scoring on land use compatibility, the intervenors argue that the Bellingham 4 site is preferable to the proposed site because Bellingham 4 abuts an industrial area on one side; however, the Company counters that the proposed site abuts Interstate 495 on one side. Although the potential existed for confusion in the application of the two criteria, the record does not support a conclusion that the Company failed to consider adequately the land use compatibility advantages of the Bellingham 4 site.

Finally, with respect to community support, the Siting Board recognizes that communities neighboring a municipality where a generating project is proposed may reasonably expect attention to concerns they may have with respect to the impacts of the proposed project on the resources of their own city or town. For this reason, municipalities adjacent to communities where projects have been proposed have in the past, as well as in the instant proceeding, been allowed to intervene before the Siting Board. However, these specific concerns are reflected in a proponent's evaluation of criteria such as water and wastewater disposal availability, dispersion environment, proximity to sensitive receptors, and land use compatibility.

The "community support" criterion serves a different purpose. A developer's evaluation of community support is in large part a practical assessment of the developer's ability to work constructively with municipal officials and residents to obtain necessary permits, negotiate mutually agreeable financial arrangements, resolve concerns regarding the impacts of the project, and bring the project to a successful conclusion. No responsible developer would proceed with a generating facility project without such an assessment. When viewed in this light, it is clear that "community support" should primarily measure support within the community in which the project is proposed. The initial decision to allow the construction of a facility such as a power plant is the prerogative of the municipality where the facility is to be located. Thus the Company's use of the community support criterion to measure support from the municipality where a considered site is located, rather than the support of that and surrounding municipalities, is reasonable.

The Siting Board has held that an applicant is best informed about community support if its site selection analysis includes an assessment of support from residents as well as from municipal officials. Here, the Company included a measure of "community support" based primarily on contact with local officials and historical public reaction to industrial development. The Siting Board notes that discussions of the specific proposed project with potential residential, commercial and industrial neighbors may alert the developer to important site specific issues that could affect the Siting Board's analysis of the cost or environmental impacts of the proposed project at a potential site. The Siting Board acknowledges that it is also possible to identify many such issues by screening potential sites based on surrounding land uses and proximity to sensitive receptors, as ANP has done. In the instant proceeding, the developer has also conducted public outreach earlier than developers in other generation facility cases recently before the Siting Board. The Siting Board notes that if outreach is not incorporated into early stages of project development, new, potentially serious concerns requiring additional mitigation or even selection of a different site may be raised.

The Siting Board has expressed varying degrees of concern regarding the Company's evaluation of three screening criteria: water availability, gas interconnect impacts, and community support. A retrospective reevaluation of the water availability and gas interconnect criteria might marginally lower the score of the proposed site relative to other sites considered by the Company. Similarly, we have noted that a retrospective reevaluation of two other criteria, "proximity to groundwater resources" and "proximity to wetland/floodplain resources", might marginally increase the relative score of the proposed site.

The Siting Board recognizes that a numerical screening analysis is only the starting point of the site selection process. As evidenced here, a sound screening process may identify a number of sites which receive similar high scores but which have different strengths and weaknesses, so that no one site is clearly superior to the others. For example, in the instant proceeding, the record indicates that the proposed site is superior to Bellingham 4 with respect to community support, zoning, and the potential for site contamination, whereas the Bellingham 4 site is preferable with respect to the gas interconnect, road and rail infrastructure, and groundwater resources. Overall, the record indicates that the proposed site, the Bellingham 4 site, and the other high-ranking sites considered by the Company have different but offsetting strengths and weaknesses as sites for the proposed generating facility. Accordingly, the Siting Board finds that the Company did not overlook or eliminate a clearly superior site for its project.

Based on an analysis of the preliminary phases, quantitative (screening level) phase and final qualitative phases of the Company's site selection process, the Siting Board finds that (1) the Company has developed a reasonable set of criteria for identifying and evaluating alternative sites, and (2) the Company has appropriately applied a reasonable set of criteria for identifying and evaluating alternative sites in a manner that ensures that it has not overlooked or eliminated any clearly superior site.

c. Geographic Diversity

In this section, the Siting Board considers whether the Company's site selection process included consideration of site alternatives with some measure of geographic diversity. The Siting Board notes that with the modification of its site selection review in this proceeding, the Siting Board's previous requirement that an applicant must provide at least one noticed alternative with some measure of geographic diversity is moot.

The Company asserted that it has identified at least two sites with some measure of geographic diversity (Exh. BEL-1, at 5-16). The Siting Board notes that there is no minimum distance that is sufficient to establish geographic diversity in any given case. The Siting Board previously has determined that two sites in the same town can provide adequate geographic diversity for a generating facility review. Millennium Power Decision,

EFSB 96-4, at 105; Berkshire Power Decision, 4 DOMSB at 357; 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, among its ten top-ranked sites the Company has provided sites with varying environmental characteristics in seven different communities.

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

3. Conclusions on the Site Selection Process

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

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

B. Environmental Impacts of the Proposed Facilities

1. Standard of Review

In implementing its statutory mandate to ensure a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost, the Siting Board requires project proponents in a case without a noticed alternative site to show that proposed facilities are sited a location 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 is superior to alternatives on the basis of balancing cost, environmental impact and reliability of supply. See Berkshire Power Decision, 4 DOMSB at 358; Silver City Decision,

3 DOMSB at 276; Berkshire Gas Company, 23 DOMSC 294, 324 (1991). Specifically, in accordance with the Scope of Review set forth in Section I.D, above, the applicant must show that its proposed facility is sited, designed and mitigated in a manner that will minimize cost and environmental impacts, and that an appropriate balance will be achieved among conflicting environmental concerns as well as among environmental impacts, cost and reliability.

An assessment of all impacts of a facility is necessary to determine whether an appropriate balance is achieved both among conflicting environmental concerns as well as among environmental impacts, cost and reliability. Berkshire Power Decision,

4 DOMSB at 358; Silver City Decision, 3 DOMSB at 276; EEC Decision, 22 DOMSC 188, 334, 336 (1991). A facility proposal which achieves that appropriate balance is one that meets the Siting Board's statutory requirement to minimize environmental impacts. Berkshire Power Decision, 4 DOMSB at 358; Silver City Decision, 3 DOMSB at 276; EEC Decision, 22 DOMSC at 334, 336.

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

22 DOMSC at 334, 335.

The Siting Board recognizes that an evaluation of the environmental, cost, and reliability trade-offs associated with a particular review must be clearly described and consistently applied, to the extent practicable, from one case to the next. Therefore, in order to determine if a project proponent has achieved the appropriate balance among environmental impacts, costs and reliability, the Siting Board must first determine if the petitioner has provided sufficient information regarding environmental impacts and potential mitigation measures in order to make such a determination. Berkshire Power Decision,

4 DOMSB at 359; Silver City Decision, 3 DOMSB at 277; 1993 BECo Decision,

1 DOMSB at 39-40, 154-155, 197. The Siting Board can then determine whether environmental impacts have been minimized. Similarly, the Siting Board must find that the project proponent has provided sufficient cost information in order to determine if the appropriate balance among environmental impacts, costs, and reliability has been achieved. Berkshire Power Decision, 4 DOMSB at 359; Silver City Decision, 3 DOMSB at 278; 1993 BECo Decision, 1 DOMSB at 40.

Accordingly, in the sections below, the Siting Board examines the environmental impacts of the proposed facilities at the proposed site to determine whether the Company's proposal minimizes specific sets 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.

2. Environmental Impacts

a. Air Quality

(1) 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"); Prevention of Significant Deterioration ("PSD") requirements; New Source Review ("NSR") requirements; and New Source Performance Standards ("NSPS") for criteria pollutants (Exh. BEL-1, at 6-2). In addition, the Company indicated that the proposed facility would fall under Title IV Sulfur Dioxide Allowances and Monitoring regulations beginning in the year 2000 (Exh. HO-EA-4.1, at 3-4). Finally, the Company stated that the Secretary of Environmental Affairs had ordered that the environmental impact report ("EIR") for the proposed facility "must consider the cumulative impacts of this facility combined with other generators within a predetermined radius"

(Exh. BEL-15, Vol. II, at App. A).

The Company indicated that, under NAAQS, all geographic areas are classified and designated as attainment, non-attainment or unclassified for the six criteria pollutants: SO_2, PM-10, NOx, CO, ground level ozone ("O_3") and lead ("Pb") (Exh. BEL-1, at 6-3). The Company further indicated that, although the Bellingham area is classified as "attainment" or "unclassified" for SO_2, PM-10, NOx, CO, and Pb, the entire Commonwealth of Massachusetts is in "serious" non-attainment for O_3 (id. at 6-4).

The Company stated that under PSD requirements, the proposed facility must

(1) demonstrate compliance with NAAQS, and (2) apply Best Available Control Technology ("BACT") to emissions of NOx, CO, and PM-10, pollutants for which emissions may potentially exceed 100 tpy (Exhs. HO-EA-4.1, at 4-6; BEL-13.2, at 4-1).

The Company further indicated that under NSR requirements, the proposed facility must apply Lowest Achievable Emission Rate ("LAER") technology and emissions offsets to any directly emitted pollutant which is a precursor to O_3, and which the proposed facility may emit at levels greater than 50 tpy (Exhs. HO-EA-4.1, at 4-1, 4-12; BEL-13.2, at 4-1). Thus, the Company must apply LAER technology to control NOx (id.). With regard to NSPS requirements, the Company indicated that emissions of regulated pollutants -- NOx and SO_2 -- would fall well below NSPS threshold levels (Exh. HO-EA-4.1, at 3-4).

In addition, the Company noted that the proposed facility would incorporate BACT for SO_2 and VOCs as well as for other non-criteria pollutants and air toxics that are regulated as part of the MDEP air plans approval process (id. at 4-6; Exh. BEL-1 at 6-6).

(2) Emissions and Impacts

(a) Description

The Company indicated that the proposed facility would emit regulated pollutants, including criteria and non-criteria pollutants, and CO_2 (Exhs. HO-EA-4.1, at 3-2, 4-1;

BEL-13.2, at 3-1, 4-1). The Company asserted, however, that air quality impacts from the proposed facility would be minimized through the use of natural gas as fuel, efficient combustion technology, advanced pollution control equipment, and acquisition of NOx offsets (Exh. BEL-1, at 6-2, 6-17). The Company also asserted that dispatch of the proposed project in preference to older generating resources in the region would result in displacement of NOx, SO_2 and CO_2 emissions (id. at 6-20).

The Company stated that its proposed facility would incorporate BACT for CO, PM-10, SO_2, Pb, and VOCs as well as both BACT and LAER for NOx (id. at 6-6). The Company further stated that emission rates for non-criteria pollutants would represent BACT for each substance. In support of its contention that the proposed facility would represent BACT and/or LAER for the identified pollutants, the Company provided information regarding control options for the proposed facility (Exh. HO-EA-4.1, at 4-1 to 4-11).

The Company estimated the quantity of pollutants that would be emitted from the proposed facility on the basis of information from manufacturers and vendors of plant equipment and from government data centers (Exhs. BEL-1, at 6-16; HO-EA-4.1, at 3-1,

4-2). The Company provided calculations of air emissions for the proposed facility based on the identification of "worst-case" operating conditions, which the Company stated would be 100 percent load, with steam augmentation, at an ambient temperature of 90 degrees Fahrenheit (Exh. BEL-13.2, at 5-1).

The Company asserted that predicted concentrations of air pollutants to be emitted by the proposed facility would be "insignificant" relative to applicable ambient air quality standards (Exhs. BEL-1, at 6-2, HO-EA-4.1, at 5-12; BEL-13.2, at 5-1). In support of its assertion, the Company provided results of local air quality modelling, which indicate that the air quality impacts of the proposed facility on ambient concentrations of criteria pollutants would be below established significant impact levels ("SILs") assuming the proposed Good Engineering Practice ("GEP") stack height of 180 feet (Exhs. HO-EA-4.1, at 5-2;

BEL-13.2, at 4-1).

The Town of Franklin expressed concern that lands within its borders would suffer from the deposition of particulate emissions originating at the proposed facility (Franklin Brief at 3). In response, the Company prepared a particulate deposition analysis using the EPA-approved ISC model which demonstrated that although the maximum predicted annual deposition rate was projected to be three kilometers southeast of the site -- a location clearly within the Town of Franklin -- deposition of particulates from the project would nonetheless represent an insignificant fraction of ongoing deposition from existing sources and background concentrations (id.; Tr. 7, at 85-92; Exh. F-RR-2).

With respect to emissions of non-criteria pollutants and air toxics, the Company stated that SCREEN3 modelling was conducted to estimate emissions of formaldehyde, sulfuric acid, and ammonia. The Company then compared the predicted concentrations of these pollutants to the applicable MDEP standards (Exhs. HO-EA-4.1, at 5-12; BEL-13.2, at 5-3). The Company stated that the resulting concentrations were predicted to be below SILs for all pollutants except formaldehyde.

The Company performed additional, more refined modelling -- using the EPA recommended ISCST3 which incorporates hourly meteorological data -- to further evaluate the operating scenario for which the concentration of formaldehyde was found, based on screening level modelling, to be above the SIL. The Company stated that its refined modelling comprised a 24 square kilometer receptor grid surrounding the facility site, and incorporated elevation data for all significant terrain features within that area

(Exh. HO-EA-4.1, at 5-13). The Company further stated that it used five years (1990 to 1994) of actual meteorological observations as inputs to the model, and indicated that the data was recorded at Worcester Airport and Bradley Field (surface data), and at Albany, New York (mixing height data) (id.). Based on its refined modelling, the Company stated that formaldehyde concentrations were predicted to be below the applicable TELs and AALs for the identified maximum impact load condition (id. at 5-21).

With respect to impacts to sensitive vegetation and soils, the Company asserted, citing supporting documentation and modelling results, that its proposed facility would have no negative impacts on sensitive vegetation or soils (Exh. BEL-1, at 6-23).

The Company asserted that operation of the proposed facility would cause economic displacement of older, higher emitting units and would therefore be expected to result in regional air quality benefits (Exh. BEL-15, at 7-1). In support of its assertion, the Company presented a displacement analysis for the five year period 2000 to 2004, indicating that regional emissions of the criteria pollutants SO_2, NOx, and CO_2 would be significantly reduced with dispatch of the proposed facility. For the two criteria pollutants SO_2 and NOx, the five-year reductions would be several times larger than the proposed facility's own emissions over the same period (id. at 6-20; Exhs. HO-N-25; HO-RR-20.10) (see Section II.A.4, above). The Company stated that the net emissions reductions attributable to the proposed facility would be expected to provide benefits with respect to two areas of environmental concern -- acid precipitation and ground-level ozone (Exh. BEL-1, at 3-21).

With respect to the analysis of cumulative impacts as ordered by the Secretary of Environmental Affairs, the Company stated that it had prepared a cumulative air impacts analysis as part of the DEIR filed in docket EFSB 97-2, for the proposed ANP-Blackstone Energy Project. The Company indicated that the analysis addressed the two projects currently proposed by ANP, and a generation project proposed for a site within the Town of Bellingham by IDC in docket EFSB 97-5. Additionally, the analysis considered other major sources in the region that met the following criteria: (1) sources within ten kilometers of the proposed facility with the potential to emit 50 tpy or more of NOx, 100 tpy or more of SO_2, or 100 tpy or more of CO, and (2) sources within 20 kilometers of the proposed facility with the potential to emit 1,000 tpy or more of NOx, SO_2, PM, or CO (Exh. BEL-13.2,

at App. C). The Company stated that based on the above criteria, its interactive source model included three proposed and nine existing sources.

The Company stated that it used the ISCST3 model with the same model inputs and meteorology as for its refined analysis conducted for the proposed ANP Blackstone project (id.). The Company stated that results of the interactive modelling demonstrated that the maximum combined concentrations of criteria pollutants from both the existing and proposed sources, plus existing background levels, would be within MAAQS and NAAQS (id. at 8-23). The Company further indicated that it conducted modeling of two subgroups of proposed and existing sources: (1) the three currently-proposed generating projects, and (2) the three proposed projects plus three existing generating facilities -- Bellingham Cogen (formerly Northeast Energy Associates), and the Milford Power and OSP projects. The Company stated that the results of the analysis showed that the contribution of these subgroups to ambient concentrations would be small as compared to MAAQS and NAAQS (id.).

(b) Analysis

The Company has demonstrated that emissions of criteria and other pollutants from the proposed facility at the proposed site would have acceptable impacts on existing air quality. The record shows that the proposed facility would include two highly-efficient combustion turbines with natural gas as the sole fuel. Additionally, the Company has indicated that the proposed facility would incorporate advanced emissions control technologies.

The Company has used reasonable and appropriate air modelling techniques to assess the impacts of emissions from the proposed facility, and has demonstrated that impacts from the proposed facility would be below SILs for all criteria emissions and for other hazardous or toxic air pollutants.

With respect to the modelling of cumulative air quality impacts from the proposed facility and other existing and proposed sources in the region, the Company has provided an analysis, using MDEP-approved protocols, which demonstrates that cumulative air impacts are projected to be within the applicable MAAQS and NAAQS for all criteria pollutants. Moreover, the analysis demonstrates that existing air quality is well within the ambient air quality standards and that emissions from the proposed facility would represent a small fraction of those standards. The Siting Board notes that the interactive source model presented in this case initially was developed at the request of the Secretary of Environmental Affairs in docket ANP Blackstone Energy Company, EFSB 97-2, and recognizes that its inclusion in the record in this case is appropriate.

(3) Offset Proposals

(a) Description

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-EA-4.1, at 4-12). The Company stated that, in Massachusetts, offsets are generated by obtaining MDEP-certified Emission Reduction Credits ("ERCs") in an amount that is five percent greater than that required 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 NOx emissions of 222 tpy, the proposed facility would require offsets for 280 tons of NOx per year (id.). The Company stated that it had identified potential sources of NOx offsets, primarily resulting from in-state shutdown credits (Tr. 7, at 18).

The Company indicated that the proposed facility would emit a maximum of 1,948,500 tpy of CO_2 and asserted that the CO_2 impacts of the proposed facility would be minimized consistent with Siting Board requirements (Exhs. BEL-1 at 6-19 to 6-20;

HO-EC-1). In researching possible CO_2 mitigation strategies for the proposed facility, the Company stated that it had requested proposals from three organizations; (1) the Conservation Law Foundation, (2) the Charles River Watershed Association ("CRWA"), and (3) the New England Forestry Foundation, all regarding projects that would result in effective CO_2 mitigation for the proposed facility (Tr. 7, at 49-50). The Company indicated that it had not yet received any detailed proposals from these entities, but that it would continue to investigate options for CO_2 mitigation (id.; Exh. HO-RR-36).

The Company further argued that the operation and dispatch of the proposed facility over the period 2000 to 2004 would result in the displacement of CO_2 emissions from other facilities, and would contribute to the minimization of CO_2 impacts from the project

(Exh. BEL-1, at 6-20). In support of its argument that the proposed facility would displace CO_2 emissions from other facilities the Company provided a displacement analysis for the identified five-year period (Exhs. HO-N-25; HO-RR-20.10). The analysis showed a five-year reduction in regional CO_2 emissions of 7,030,000 tons, or 85 percent of the proposed facility's 8,314,000 tons of CO_2 emissions over the same period (Exhs. HO-N-25;

HO-RR-20.10).

Finally, the Company considered the impact of its proposed on-site tree clearing on annual CO_2 assimilation. The Company asserted that, in terms of CO_2 impacts, the effect of the proposed tree clearing would be insignificant as compared to stack emissions, and estimated that lost assimilation capacity as a result of clearing 26 acres of trees would equate to approximately 100 tpy of CO_2 (Exhs. HO-RR-37; Tr. 7, at 51-52).

(b) Analysis

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

In the Dighton Power Decision, the Siting Board set forth a new approach to the mitigation of CO_2 emissions that required generating facilities to make a monetary contribution, within the early years of facility operation, to one or more cost-effective CO_2 offset programs, with such program(s) to be selected in consultation with the Siting

Board Staff. EFSB 96-3, at 42-43. In Dighton, the Siting Board expressed an expectation that the contributions of future project developers would reflect that set forth in Dighton, which was based on an offset of one percent of annual facility CO_2 emissions, at $1.50 per ton, to be donated in the early years of facility operation. Id. at 43.

Here, the Company has proposed to contribute an amount, based on the proposed facility's annual maximum CO_2 emissions over 20 years of operation, that would be consistent with those ordered in recent generating facility cases. Based on projected maximum annual CO_2 emissions of 1,948,500 tpy for the proposed facility, the total contribution requirement would be $584,550. In a past case, the Siting Board allowed for payment of the contribution amount over five years, or alternatively as a first-year equivalent value, calculated by summing the five annual increments, and then discounting the stream of contributions to reflect constant first-year dollars. Dighton Power Decision, EFSB 96-3, at 40-44. In a more recent case, a similar methodology was used to calculate the appropriate first-year contribution, although in that instance, the Siting Board first escalated the five annual increments to reflect a potential for increased cost in future years to achieve the targeted offset levels. Millennium Power Decision, EFSB 96-4, at 114, 117-118. Therefore, consistent with the CO_2 mitigation requirement set forth in the Millennium Power Decision, the Siting Board requires the Company to provide CO_2 offsets through a total contribution of $620,690 to be paid in five annual installments during the first five years of facility operation, to a cost-effective CO_2 offset program or programs to be selected upon consultation with the Staff of the Siting Board. Alternatively, the Company may elect to provide the entire contribution within the first year of facility operation. If the Company so chooses, the CO_2 offset requirement would be satisfied by a first-year contribution in the amount of $467,940 to a cost-effective CO_2 offset program or programs to be selected upon consultation with the Staff of the Siting Board. With respect to the impact of tree clearing on CO_2, the record indicates that 26 acres of trees would be removed to accommodate the facility footprint, and the Company has stated that such acreage represents an estimated CO_2 sequestration capacity of 100 tpy, or roughly four tpy of CO_2 per acre. The record does not contain additional information on the assumptions used to arrive at the identified annual assimilation rate. Specifically, the record does not specify operative assumptions as to the relative age of forest growth or the types of species present, i.e., primarily coniferous versus primarily deciduous -- factors likely to be significant in determining the actual CO_2 sequestration rate.

In a number of past reviews, developers of generating facilities have proposed offsetting facility CO_2 emissions through contributions to MASS Releaf, a state program which plants shade trees throughout the commonwealth. Altresco Lynn Decision,

2 DOMSB at 183-186, 217-220; Eastern Energy Corporation Decision on Compliance,

25 DOMSC at 349. In those cases, it was assumed that each tree planted would sequester 30 tons of CO_2 over a 40-year period of analysis, yielding an annual average of 3/4 tpy of CO_2 per tree. Altresco Lynn Decision, 2 DOMSB at 219; Eastern Energy Corporation Decision on Compliance, 25 DOMSC at 350, fn. 67. To ensure consistency between

cases in establishing required offset levels, the Siting Board determined that it was appropriate to adjust required tree planting to reflect case-by-case differences in on-site tree clearing required for project development. Altresco Lynn Decision, 2 DOMSB at 219. Based on sequestration levels assumed for tree planting under the MASS Releaf program, the Siting Board accepted adjustment allowances of as high as 225 tpy per acre of cleared trees. Id. Thus these adjustments for on-site tree clearing were as much as 50 times or more the allowance of 4 tpy per acre proposed by ANP-Bellingham.

The Siting Board recognizes that the application in past reviews of tree-clearing adjustment allowances based on sequestration rates assumed for planted urban shade trees may have resulted in some overstating of the adjustment allowances. At the same time, the Company has not adequately supported its proposed adjustment allowance, and the Siting Board is concerned that it may understate the adjustment that would be appropriate for the clearing of woodlands at the proposed site. Therefore, the Siting Board will determine an adjustment allowance for the proposed tree clearing based on balanced consideration of the record and available precedent. For purposes of this review, the Siting Board assumes that a sequestration rate of 30 tpy of CO_2 per acre, applied over a 30 year period, provides a reasonable basis to estimate the CO_2 sequestration that would be lost as a result of clearing the proposed site. Thus the allowance for clearing 26 acres would be 23,400 tons of CO_2. At $1.50 per ton, this yields an additional first year offset contribution of $35,100 to the CO_2 offset program or programs selected to offset facility emissions.

Accordingly, the Siting Board finds that, with implementation of the foregoing NOx and CO_2 offset measures, the environmental impacts of the proposed facility at the proposed site would be minimized with respect to air quality.

b. Water-Related Impacts

(1) 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 provided estimates of water supply needs for the proposed facility for two possible operating designs or scenarios: (1) baseload operations of 545 MW, without steam augmentation; and (2) use of steam augmentation to generate an additional 40 MW for 10 percent of the year, 12 percent of the year or 20 percent of the year (Tr. 10, at 63, 124 to 163; Tr. 11, at 50 to 54). The Company stated that it expected to use steam augmentation 10 percent, or approximately 37 days of each year, but indicated that it had contracted for sufficient water to use steam augmentation for up to 20 percent or 73 days of the year

(Tr. 11, at 52). Differences in the Company's water supply estimates correlated to differences in the number of days of steam augmentation.

The Company stated that the proposed project would incorporate air cooled condensers in order to minimize water requirements to the maximum extent possible (Exh. BEL-1).

The Company indicated that baseload water supply needs for the proposed facility, including potable water supply, would be approximately 14,000 gallons per day ("gpd") or 4.2 million gallons per year ("mgy"), based on 302.2 days of operation annually (Tr. 10,

at 129, 131). The Company also indicated that steam augmentation would increase the average daily water requirement of the proposed facility (Tr. 11, at 50 to 54). The Company provided estimates for water requirements above baseload water supply for its three scenarios incorporating steam augmentation (id.). These ranged from an additional 25 mgy with

37 days of steam augmentation to an additional 50 mgy with 73 days of steam augmentation based on 302.2 days of plant operation annually (id.). The Company estimated the combined baseload and steam augmentation water supply requirements for the proposed facility at

29.2 mgy (on average 96,600 gpd for 302.2 days) for 37 days of steam augmentation and 54.2 mgy (on average 179,000 gpd for 302.2 days) for 73 days of steam augmentation (id.).

The Company indicated that water use for the proposed facility might in theory be as much as 684,000 gpd based on its vendor's estimate that steam augmentation would require 28,500 gallons of water per hour (Exh. HO-EW-8). The Company explained, however, that because use of steam augmentation would correspond to periods of peak power production -- approximately seven to eight hours per day -- daily water use likely would be much less than the theoretical maximum (Exhs. HO-EW-7; HO-EW-8).

The Company stated that its water supply would come primarily from Town of Bellingham municipal water supplies (Exh. BEL-1, at 6-31). The Company provided

a copy of its Agreement for Water and Sewer Services ("Agreement") with the Town of Bellingham (Exh. HO-V-7.1). The Agreement states, in part, that the Company has the right to withdraw water from Bellingham's municipal water supply in quantities up to 100,000 gpd during the period March 15 through November 15, and up to 250,000 gpd during the period November 15 through March 15 (id. at 3). The Company indicated that it would tie into the municipal system through a connection extending into the site from an existing Maple Street water line, predominantly 12 inches in diameter (Exh. BEL-1, at 6-31).

The Company stated that for summer steam augmentation purposes, as well as for emergency fire flows, the proposed facility would include a raw water tank, as well as a demineralized water tank (id.). The Company testified that the demineralization tank would hold 1.5 million gallons and the raw water tank would hold one million gallons, of which 700,000 gallons would be available for demineralization and use in the facility and 300,000 gallons would serve as a permanent reservoir for fire-fighting purposes (Tr. 10, at 66). The Company stated that the raw water storage and demineralized storage on site would yield enough water for 3.7 days' operation of the proposed facility in the summer at the maximum rate, i.e., with steam augmentation (id., at 67-68).

The Company indicated that it would fill the demineralized and raw water tanks with the water allocated by the Town to the proposed facility during periods when less than the maximum allowable flows are required and that water volumes taken to fill the tanks thereafter would match the daily water needs of the proposed facility (Exh. BEL-1, at 6-31).

The Company indicated that the water supply for the Town of Bellingham comes from nine municipal wells in two watersheds, the watersheds of the Charles and the Blackstone River basins and their sub-basins (Exhs. EW-1.1; HO-RR-49). The Company asserted that water resources would not be significantly affected by the proposed facility (Exh. BEL-1, at 6-24). In support, the Company provided data for the Town municipal water supply wells ("supply wells") by river basin, including permitted withdrawal volumes, actual average daily use, and total annual use for the years 1993 through 1996 (Exh. HO-RR-49) (see Appendix, Table A-1).

The Company also provided a comparison of the withdrawal rates of each

of the supply wells to groundwater recharge rates for the 1993 through 1996 period

(Exh. HO-RR-51). In its comparison, the Company indicated that the estimated volumes of recharge to each supply well are two to four times the amount pumped historically on average (id.). Based on its comparison and analysis, the Company argued that the maximum withdrawals for the proposed facility would not significantly change the relationship between the recharge available to each supply well and the amount the supply wells would be pumping even given maximum water withdrawal under the Company's contract (id.) (see Appendix, Table A-2).

In addition, the Company examined the impact of estimated population growth on water use projections within the Charles and Blackstone River basins for the Town of Bellingham through the year 2020 (Exh. HO-RR-52). The Company relied on several sources for its analysis, including a report of historic and projected water use for the Charles River basin prepared by the Massachusetts Department of Environmental Management ("MA DEM") and a 1997 study by consultants for the Town of Bellingham which modeled the Town's future growth (id.; Exh. EFSB-1). The Company compared projections of population growth against actual water use and future permitted water use from the Charles and Blackstone River basins for the Town of Bellingham under the Massachusetts Water Management Act ("MA WMA") (Exh. HO-RR-52).

The Company indicated that annual average daily water withdrawals in recent years through 1996 were well below the MA WMA permitted water withdrawal for the Town of Bellingham (Exh. HO-RR-52.2). The Company also indicated that through 2010, the years for which information was available, the MA DEM projected water use for the Town of Bellingham increased at a rate equal to or less than the rate of permitted water use (id.)

The Company also submitted 7Q10 low flow data and average daily summer (July through September) flow data for four locations, the Millis and Waltham gauging stations in the Charles River Basin and the Woonsocket and Peters Brook gauging stations in the Blackstone River Basin (Exhs. HO-RR-54, HO-RR-54S). The Company stated that the maximum daily water withdrawals during the summer for the proposed facility, 0.10 mgd, would be distributed evenly between the Charles and Blackstone River basins. The Company acknowledged that increased groundwater withdrawals could ultimately affect flow amounts in rivers within the respective basins, but indicated that any such effect would be insignificant relative to the historical flow levels, even during low flow (id.). The Company therefore asserted that associated impacts on the Charles and Blackstone River basins would be acceptable (Exh. HO-RR-54, HO-RR-54S) (see Appendix, Table A-3).

The Company also discussed MA WMA permits issued by MDEP in 1989-1990 and in 1995-1997, authorizing Town of Bellingham well withdrawals from the Charles River basin and Peters Brook subbasin, as well as a 1989 report by MDEM identifying habitat attributes and associated water management issues in Peters Brook (Exhs. HO-RR-53; HO-RR-94A; HO-RR-94B). The MA WMA permitted withdrawal rates, originally set in the 1989-1990 permits, were reaffirmed in 1995-1997 in conjunction with Town requests for new wells (Exhs. HO-RR-94A; HO-RR-94B). The Company stated that a 1989 MA DEM report on the Blackstone River basin and its subbasins identified Peters Brook as a cold water fishery and possible habitat for the American Brook Lamprey, but did not conclude that special constraints should be placed on Town of Bellingham withdrawals from Peters Brook (Exhs. HO-RR-53; HO-RR-94A; HO-RR-94B). The Company added that the Town of Bellingham's water withdrawal permit for the Blackstone River basin wells had been reissued since publication of MA DEM's report, and reaffirmed previously-authorized withdrawal amounts without placing any special restrictions on such withdrawals (Exhs. HO-RR-53;

HO-RR-94A; HO-RR-94B).

The Company also provided a copy of a water conservation plan for Bellingham and Blackstone developed by the CRWA and funded by the Company (Exh. HO-RR-55.1). The Company stated that it initiated the CRWA water conservation program ("CRWA program") to reduce demand on the Town of Bellingham's water supply system (Tr. 9, at 110 to 111; Tr. 10, at 12 to 16). According to CRWA estimates provided by the Company, total savings of drinking water and groundwater resources in Bellingham and Blackstone from the CRWA program would be 138.9 mgy and 18.26 mgy respectively. The program would include five projects with estimated benefits for the two towns, combined, as follows: retrofitting of toilets and shower heads (6.5 mgy savings to drinking water), leak detection (105.4 mgy savings to drinking water), public awareness program (27 mgy savings to drinking water), stormwater remediation program for recharge infiltration (12 mgy recharge to groundwater), and septic system repair (6.26 mgy recharge to groundwater) (Exhs. HO-RR-55.1;

HO-RR-86; HO-RR-87).

The Company admitted that its planned use of steam augmentation to increase the output of the proposed project during periods of peak load would substantially increase its water consumption (Tr. 11, at 112, 116 to 117). The Company noted that conventional peaking facilities, which serve the same role as steam augmentation, can, depending on technology, operate with no more water than that necessary for sanitary needs (id. at 115

to 116). However, the Company argued that the impacts of conventional peaking facilities, including land use, noise, visual, safety and, potentially, air impacts, would more than offset the water use impacts of the proposed facility (id. at 108 to 109).

With respect to relative costs, the Company asserted that a conventional peaking unit would involve higher heat rate (lower efficiency) and greater cost than would comparable output from steam augmentation at the proposed facility (Exh. HO-RR-72; Tr. 11, at 122 to 123).' The Company stated that the increase in design and capital costs of construction associated with steam augmentation capability would be negligible, and that no incremental fixed costs would be associated with steam augmentation (Exh. HO-EW-8). The Company stated that the additional variable operating costs would include the cost of water, water treatment and supplemental fuel costs (id.). The Company stated that steam augmentation would result in additional water resource impacts but asserted that such impacts would be offset by the CRWA program (id.).

The Company stated that no portion of the facility footprint or its related features on the site, including the temporary parking and laydown areas during construction, would be located within jurisdictional wetlands (Exh. HO-RR-70; Tr. 10, at 86 to 87). The Company indicated however, that some components ancillary to the proposed facility, such as the access roadway and some of the stormwater drainage features, would be placed within the 100-foot buffer zone of bordering vegetated wetlands (Exh. HO-RR-70; Tr. 10, at 87).

The Company asserted that impacts to wetlands associated with installation of the off-site portion of the natural gas pipeline interconnect for the proposed facility could be minimized by the use of directional drilling to cross the Charles River (Tr. 10, at 90 to 92). The Company stated that AGT, which would be responsible for the installation of the natural gas interconnect for the proposed facility, estimated that directional drilling would disturb approximately 131 square feet of nonforested wetland area at the Charles River (id. at 92). Algonquin expected that impacts to wetlands along the remainder of the route would total 32,000 square feet (id.).

The Company indicated that the use of air cooled condensers and internal water recycling would result in low wastewater flows (Exh. BEL-15, at 12-5). The Company stated that process discharge volumes would range from approximately 3,400 gpd during normal baseload operations to 5,000 - 8,000 gpd when the proposed facility operates with frequent stops and starts (id.; Exh. NEA-13). The Company stated that the use of steam augmentation would not affect wastewater discharge volumes (Tr. 11, at 138). The Company further stated that a greater discharge volume, 17,300 gpd on average and 27,000 gpd at maximum, would occasionally result due to equipment blowdown, equipment washdown, and maintenance activities (Tr. 11, at 135 to 136).

The Company documented allocation by the Town of a firm 10,000 gpd of average daily sewer capacity at the Charles River Pollution Control District Plant for the proposed facility (Exh. HO-RR-BCC-1). The Company stated that discharge from major maintenance inspections would occur over periods of up to several days, but that the Town would make special provision to allow the proposed facility to discharge its maximum anticipated wastewater discharge as necessary (Exh. HO-RR-63; Tr. 11, at 134 to 137). The Company indicated that oil contaminated effluents would be routed through an oil separator before being discharged to the sewer system (Exh. BEL-1, at 6-30).

The Company indicated that it had developed a stormwater management plan for the proposed facility designed to minimize pollutants in the proposed facility's stormwater discharges, assure compliance with the terms and conditions of the National Pollutant Discharge Elimination System ("NPDES") Multi-Sector General Permit requirements, attenuate peak stormwater runoff discharge rates to values not greater than the predevelopment rates, and meet the Massachusetts Stormwater Management Performance Standards (Exh. BCC(2)-W5.1, at 4-1; Tr. 11, at 155). The Company provided a copy of its Notice of Intent to the Bellingham Conservation Commission containing details of its stormwater management plan (Exh. BCC(2)-W5.1). The Company stated that peak stormwater runoff rates with the facility in operation actually would be less than the peak runoff rates under existing site conditions as a result of its proposed stormwater management plan design (id. at 4-8). The Company further stated that it anticipated no deterioration of off-site resources due to the water quality of stormwater runoff from the proposed facilities (id. at 4-8).

(2) Positions of the Intervenors

The Town of Franklin argued that the Agreement executed by the Company and the Town of Bellingham would not limit the Company's water withdrawals from Bellingham's water supply to 100,000 gpd during March 15 through November 15 and

250,000 gpd during the period November 15 through March 15, as stated by the Company (Franklin Brief at 18 to 19; BCC Brief at 3 to 4). The Town of Franklin contended that the Company would not necessarily be limited to withdrawal of the water quantities specified in the Agreement, but only to withdrawal of specific quantities of water at the Town's standard rates (Franklin Brief at 19). The Town of Franklin further argued that the Agreement explicitly acknowledged the Company's ability to withdraw additional quantities of water because it allowed for billing the Company at a rate 1.4 times the highest rate block for all usage over the specified amounts indicated (id.). In addition, the Town of Franklin took issue with the statement by the Company's witness that the Town of Bellingham would control any deliveries of Town water to the Company beyond the 100,000/250,000 gpd levels described (id.). The Town of Franklin argued that Bellingham has no legal authority to refuse to supply water to the Company when such water is available, and that the Agreement does not purport to confer such authority (id. at 19 to 20). On the basis of its arguments, the Town of Franklin urged the Siting Board, in the event the proposed facility was not denied, to prohibit or limit steam augmentation at the proposed facility and to limit the Company's daily and average daily water usage (id. at 29).

The Bellingham Conservation Commission submitted arguments mirroring those of the Town of Franklin with respect to water supply for the Company's proposed facility in Bellingham (BCC Brief at 3 to 4). On the basis of arguments presented, the Bellingham Conservation Commission asserted that approval of the Company's proposed facility should only occur given some guarantee that withdrawals for the proposed facility would not exceed 100,000 gpd from March 15 to November 15, and 250,000 gpd from November 15 to

March 15 (id.).

The Town of Franklin and the Bellingham Conservation Commission also expressed concern regarding the wetlands impacts of Algonquin's proposal to construct a natural gas pipeline under the Charles River to the proposed site (Franklin Brief at 28 to 29; BCC Brief at 4-5). The Town of Franklin argued that the Algonquin interconnect and the proposed facility are part of the same project and that the temporary and permanent impacts to bordering vegetated wetland are in excess of DEP's standards (Franklin Brief at 28 to 29). The Town of Franklin further asserted that there is a "reasonable alternative route" for the proposed pipeline -- the entire project could be located at another site in Bellingham, avoiding a Charles River crossing -- and that the proposed facility therefore fails to comply with DEP wetland standards (id.).

The Bellingham Conservation Commission noted that Algonquin has not committed to using directional drilling to cross the Charles River, and that the alternative, an open trench crossing, would have significantly greater impacts to wetlands (BCC Brief at 4 to 5). In addition, the Bellingham Conservation Commission indicated that it had identified route modifications that could eliminate alterations to wetland number one as identified in Algonquin's 401 Water Quality Certification Application for the proposed natural gas pipeline interconnect (id. at 5). The Bellingham Conservation Commission argued that use of directional drilling and adoption of its suggested route modifications were key to minimizing the wetlands impacts associated with the proposed natural gas pipeline interconnect (id.). The Bellingham Conservation Commission also wished to ensure that an appropriate review would occur if the Company decided to pursue a second gas utility interconnection to Tennessee Gas Pipeline (id.).

The Town of Franklin expressed concern with respect to the amount of wastewater discharge capacity available to the Company at the Charles River Pollution Control District and argued that the Company should develop a contingency plan for trucked removal of wastewater beyond its daily average capacity discharge (Franklin Brief at 22).

(3) Analysis

ANP has undertaken a significant and effective design effort to minimize the proposed facility's water supply needs during baseload operation. The record demonstrates that, due to the incorporation of air cooled condensers and other water conservation measures, the water supply needs of the proposed facility during baseload operation can be met with 14,000 gpd -- substantially less (by a factor of more than two) than the water supply needs of the most water-efficient plant previously approved by the Siting Board (see n.93, below). The Siting Board therefore finds that the water supply impacts of the proposed facility have been minimized during baseload operations.

ANP also proposes, however, to bolster the output of the proposed facility with steam augmentation for up to 20 percent of the operating year. Assuming use of steam augmentation for 10 percent of the operating year -- the level that the Company expects -- water use would increase to an average of 96,600 gpd. The Company argues that the proposed use of steam augmentation is consistent with the Siting Board's mandate to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

According to the Company's calculations, steam augmentation at the proposed facility would use 28,500 gallons of water per hour to increase power production by 40 MW at times of peak demand. The Siting Board notes that, even assuming operation with steam augmentation for 20 percent of the operating year, the proposed facility would use less water on a per-MW basis than any generating facility previously approved by the Siting Board.

The Company has argued that producing comparable additional power with a conventional peaking unit or other alternative would (a) cost more to construct and operate and (b) involve a range of undesirable environmental consequences which would more than offset the extra water use of the proposed project. The record indicates that, in contrast to identified alternatives, ANP's proposed peaking capability would involve essentially no additional capital cost. Further, proposed operation with steam augmentation would achieve a better heat rate than new simple cycle peaking capacity and, unlike other alternatives, have no adverse effect on baseload operating efficiency. The proposed peaking capability also would result in lower regional air emissions than alternatives, given its efficiency advantages, and would avoid land use and other environmental impacts associated with alternative new construction of peaking capacity.

Given these benefits, and the proposed facility's low per-MW water consumption even during steam augmentation, the Siting Board agrees that steam augmentation would contribute to a least-cost, least-environmental impact energy supply if associated water impacts are acceptable given resource constraints. The question of the acceptability of water impacts hinges in particular on whether the proposed facility's water use will strain the Town of Bellingham's municipal water supply or the basin resources on which the water system relies. We therefore examine the water consumption of the proposed facility in terms of water availability, impact on watersheds and proposed mitigation. Because of the number of proposed and existing power plants in the Bellingham-Blackstone area, we consider issues related to the water consumption of the proposed Bellingham facility in the context of existing water use at the Milford Power and NEA facilities, and the proposed use by the Bellingham, Blackstone and IDC facilities.

The Company claims that it has signed a contract which will limit water withdrawals for its proposed facility to levels well within the capacity of Bellingham's municipal water system and its contributing watersheds. The record demonstrates that ANP will have the right to withdraw water in quantities of up to 100,000 gpd during the period March 15 through November 15, to be billed according to the rate structure used for billing all customers of the Town of Bellingham's water system, and in quantities of up to 250,000 gpd during the period November 15 through March 15, to be similarly billed. The record also shows that there is provision in the Company's Agreement with the Town for the Company to be billed at a rate of 1.4 times the highest rate block for all usage over the daily averages noted above. It cannot be definitively determined, based on the Company's Agreement with the Town of Bellingham, that the Company is contractually limited to 54.75 mgy from the Bellingham municipal water system. It is significant, however, that the Company has stated on the record that this is its impression of its Agreement with Bellingham. The Siting Board also recognizes that steam augmentation provides peaking capacity, and that the Company's expectation that it will use steam augmentation approximately 10 percent of the time therefore is realistic. The Siting Board notes that even under the Company's highest water use scenario, which involves the use of steam augmentation for 20 percent of the year, maximum water withdrawal from Bellingham's water supply would be 54.2 mgy.

The record also demonstrates that the permitted capacity of Town wells can accommodate withdrawals for the proposed facility at the rate of 54.2 mgy in addition to all other present Town withdrawals. In addition, the record demonstrates that the combined water supply requirements of the Town and the proposed facility will continue to increase more slowly than the permitted capacity of Town wells under the MA WMA. Furthermore, while new development over time can be expected to result in additional water customers, the record demonstrates that water use increases in Bellingham have slowed in recent years and are projected to increase at a declining rate over time (see Exh. HO-RR-52, at 2).

With respect to the Company's analysis of the impact of projected withdrawals from the Bellingham municipal water supply, the record demonstrates that, based on 1993-1996 data, precipitation recharge for Town of Bellingham wells is above the combined levels of average annual aquifer withdrawals plus future annual withdrawals for the proposed facility. In addition, the record demonstrates that there are no conflicts between the proposed facility's demand on the public well system in Bellingham and the use of private wells, because the aquifers drawn upon are likely to be different.

Water for the proposed facility will be withdrawn from Town of Bellingham wells in two watersheds, those of the Charles and the Blackstone Rivers. Water from the Blackstone River will come, more specifically, from Peters Brook, a Blackstone River tributary.

The record demonstrates that the Blackstone River basin as a whole has ample resources for Bellingham town wells even with withdrawals for the proposed facility, but that the water resources of the Charles River basin and the Peters Brook subbasin are more thinly stretched. In these two waterways, water requirements for the proposed project and permitted increases in water withdrawal of the Town represent a larger share of 7Q10 flow. While withdrawals from the Charles River and Peters Brook are not presently restricted, the record shows that state withdrawal permits do not require extensive environmental review. In addition, the Bellingham-Medway aquifer contributes to the streamflow of the Charles River as well as underlying four of the Town of Bellingham wells which would supply water to the proposed facility. The record contains reports which document the efforts of water managers to assess long-term water availability, consistent with maintaining environmental objectives such as ensuring minimum streamflow or otherwise protecting identified resources. Thus, meeting commonly cited minimum streamflow criteria, if required for the Charles, might trigger corresponding limits on withdrawals from the Bellingham-Medway aquifer. Given such potential conflicts and constraints, the Siting Board cannot simply rely on the Company's argument that its water withdrawals would be a small percent of downstream flow in order to conclude that its proposed water use with augmentation is consistent with minimizing environmental impact.

These real concerns about watershed impacts are offset by the fact that the Company intends to fund a CRWA-developed water conservation program for Bellingham and Blackstone, which is expected to reduce water demand and improve water use efficiency, providing net benefits of 1.4 times the combined withdrawals of the ANP Bellingham and ANP Blackstone facilities, assuming steam augmentation 20 percent of the year. The Siting Board notes that this estimate is subject to some uncertainty. For example, water savings from leak detection efforts may be overstated due to existing leak detection programs, and undetected leaks may flow to the same aquifers from which municipal water supplies are drawn. Nonetheless, the Company-funded program is likely to produce significant water conservation benefits in the vicinity of the proposed facility, and has the potential to fully or substantially offset the water requirements of the proposed facility -- a level of mitigation not present in previous Siting Board reviews in which water use was an issue.

The Siting Board commends ANP's creative approach to mitigating the water supply and associated water resource impacts of its proposed facility. We view the CRWA program as a model for would-be developers of future generation projects to emulate, particularly at sites where water supply is or may likely become a special concern. The level of mitigation offered by the Company-funded CRWA program is particularly important given that the proposed facility would be sited in an area where impacts on water supply include several existing and planned generation projects in addition to the proposed facility. In this setting, it is both important and appropriate that a new consumptive water use of the size the Company proposes be mitigated by a program capable of substantially, if not fully, offsetting the added water use. It is similarly important, on a community level, that the progress to date in holding down or avoiding water use increases be maintained.

Given their importance, it is appropriate that the commitments and expectations in the record relating to community water use and conservation be monitored. Toward that end, the Siting Board directs the Company to work with CRWA to ensure periodic documentation of program activities and results to the Company, and to share periodic reports with Town of Bellingham officials and the Siting Board.

The Bellingham Conservation Commission and the Town of Franklin have both expressed concerns with respect to the Company's proposed water usage. The Town of Franklin has asked the Siting Board, in the event the proposed facility is not denied, to limit the Company's water usage on a daily or average daily basis. However, as is clear from the analysis above, it is annual, and not daily, impacts to groundwater which are of concern. Based on the Siting Board's analysis, even the Company's projected maximum water withdrawals will fall within the Company's contractual limits for water at standard rates from the Town of Bellingham's municipal water supply system. The record also shows that the financial disincentives are such that the Company is unlikely to withdraw more water than the projected maximum for its proposed facility. In addition, impacts on watersheds are acceptable, given recent trends in community water use and the extent of mitigation offered by the proposed CRWA program. Thus the Siting Board is satisfied that the Company has addressed concerns associated with water withdrawals for its proposed facilities; specifically, the Siting Board sees no need to impose the condition requested by the Town of Franklin.

Accordingly, the Siting Board finds that with implementation of the above condition, the environmental impacts of the proposed facility would be minimized with respect to water supply.

The record demonstrates that impacts to wetlands and wetland buffer zones on-site would be minimized. However, some question remains as to whether the wetlands impacts associated with construction of the natural gas pipeline interconnect for the proposed facility will be minimized. The use of an open trench crossing, rather than directional drilling, to cross the Charles River would greatly increase the total wetlands impacts resulting from construction of the proposed facility and associated projects, and it remains unclear at this time whether Algonquin is committed to using directional drilling techniques.

While the natural gas pipeline interconnect is ancillary to the proposed facility, it is subject to the jurisdiction of the FERC, rather than the Siting Board, and its route is therefore not the subject of this proceeding. However, concerns about its impacts will not go unaddressed. The Siting Board regularly intervenes with respect to the environmental impacts of such pipeline projects before the FERC. In addition, Algonquin's plans for installing its proposed gas pipeline across the Charles and through bordering vegetated wetlands are addressed by the Bellingham Conservation Commission in its review of Algonquin's Notice of Intent for its proposed project.[106] (See Section III.B.2.g, below, for a discussion of land use impacts related to the AGT pipeline.)

The Siting Board notes that a second gas utility interconnection to Tennessee Gas Pipeline at this time would constitute a change in plans for the proposed facility, requiring Siting Board notification. If the Company opts to install a second gas utility interconnection in the future, such construction also would require filings with FERC and the Bellingham Conservation Commission.

Accordingly, the Siting Board finds that the environmental impacts of the proposed facility would be minimized with respect to on-site wetlands and construction impacts.

The Company has demonstrated that it has a comprehensive plan for minimizing impacts to all water resources resulting from wastewater and stormwater discharge from the proposed facility, and that its plan meets all applicable government regulatory policy requirements.

Accordingly, the Siting Board finds that impacts to all water resources resulting from wastewater and stormwater discharge from the proposed facility would be minimized.

c. Visual Impacts

(1) Description

The Company submitted an evaluation of the potential visual impacts of the proposed facility at the proposed site (Exh. BEL-1, at 6-70 to 6-82; HO-EA-4.1, at 5-22, and App. C; HO-EV-1 to HO-EV-15; HO-RR-38 to HO-RR-45; TF-AP1, TF-AP-2, TF-AQ-10; F-RR-3 to F-RR-6). As part of its evaluation of visual impacts, the Company conducted viewshed analyses of the surrounding areas (Exh. BEL-1, at Figs. 6.7-1 to 6.7-10). The Company identified and mapped areas within approximately 1.5 to 2.0 miles of the proposed site from which the 180 foot stacks and other facility structures might be visible (id. at 6-72). Within areas identified as potentially having views of the proposed facility, the Company selected a number of visual receptor points on the basis of land use, proximity to the site and potential impacts (id. at Figs 6.7-1 to 6.7-10). The Company provided additional visual receptor locations and modified certain of the exhibits at the request of Staff and an intervenor

(Exhs. HO-EV-6.1-6.6; HO-RR-38 to HO-RR-45; F-RR-3 to F-RR-6). The Company presented existing views for a range of seasonal conditions by means of photographs taken at the identified locations looking toward the proposed site (Exhs. BEL-1, at Figs. 6.7-1 to

6.7-10; HO-EV-6.1-6.6; HO-RR-38 to HO-RR-45; F-RR-3 to F-RR-6). For each photograph, the Company then developed a computer-generated perspective of the proposed facility as it would appear at that specific location, and superimposed the perspective on the associated photograph (Exhs. BEL-1, at Figs. 6.7-1 to 6.7-10; HO-EV-6.1-6.6; HO-RR-38 to HO-RR-45; F-RR-3 to F-RR-6).

The Company also analyzed the meteorological and operating conditions under which visible exhaust plumes likely would emanate from the main stacks of the proposed facility (Exhs. HO-EA-4.1, at 5-22; HO-EV-10 (Rev.)). The Company indicated that over the course of a year, plumes of over 50 meters would be visible approximately 50 percent of daylight hours, and plumes of 100 meters or more would be visible approximately 28 percent of the daylight hours (Exh. HO-EV-10.1 (Rev.)).[107] The Company also described the MDEP standard with respect to the opacity[108] of plumes from fossil fuel utilization facilities, and indicated that plume opacities for the proposed facility would be well below the regulatory limit of 20 percent (Exh. HO-EA-4.1, at 3-6, App. C.; Tr. 7, at 45-46).

Finally, the Company indicated that it had reviewed the Massachusetts Landscape Inventory, and had determined that no distinctive or noteworthy landscapes are identified in the project vicinity, and that therefore no such areas would be impacted by the proposed facility (Exh. HO-EV-9).

The Company asserted the proposed facility would be screened from view in most directions and that, at those locations where the facility would be visible, its effect would generally be limited by surrounding land uses, terrain, vegetation and distance (Exh. BEL-1, at 6-70 to 6-74). In addition the Company asserted, citing an approved Special Permit from the Bellingham ZBA, that views of the proposed facility would be consistent with the industrial zoning of the proposed site and its immediate surroundings (Company Brief at 147).

The Company indicated that both the facility structures and stacks would be visible from certain areas to the east of the facility, including portions of Maple Street and adjacent properties, including residences, a restaurant, and a golf course (Exhs. BEL-1, at 6-80, 6-81; HO-RR-44; Tr. 8, at 61, 70, 74). The Company indicated that after construction, it would replant trees along the western edge of the NEP ROW (except in the area of the electrical interconnect) in order to screen views of the facility from locations along Maple Street (Tr. 8, at 98-100). The Company added that views of the facility from receptors to the north, west and south of the site generally would be limited to more distant views of the stack tops as seen through and above existing vegetation (Exh. BEL-1, at 6-74 to 6-82). The Company provided additional viewshed exhibits from residential areas further to the northeast, east, and south within the Town of Franklin and indicated that views of the facility from these locations, where present, also would be limited by distance and would be restricted to the tops of the stacks as seen above existing vegetation (Exhs. HO-EV-6; HO-EV-13; F-RR-4;

F-RR-5; Tr. 8, at 46).

The Town of Franklin argued that the Company had failed to characterize adequately the visual impacts of the proposed facility because its viewshed exhibits did not include representations of visible plumes from the facility stacks, despite evidence in the record which indicated that visible plumes of 50 meters or more in length would be visible for greater than 50 percent of daylight hours (Tr. 8, at 131-133; Tr 15, at 24; Franklin Brief at 17; Franklin Reply Brief at 6). Citing testimony by Mr. Sellars that operating with steam augmentation results in longer, more visible plumes, Franklin further asserted that the Company could mitigate the visual impact of plumes by foregoing steam augmentation (Franklin Reply Brief at 6). The Company responded that because presence and length of visible plumes is intermittent and variable, there would be little value in attempting to provide visual representation of plume impacts (Company Reply Brief at 16).

The Company stated that the facility structures will be painted a neutral color, typical of modern industrial buildings, to minimize the visual impacts of the proposed facility

(Exhs. BEL-1, at 6-71; HO-EV-7; Tr. 8, at 57-60, 78-85). The Company explained that in selecting the final color(s) for the proposed facility, it intended to consider opinions expressed by both citizens and local officials, and would also rely to a degree on the experience of its EPC contractor, ABB, regarding color choice (Tr. 8, at 59-60).

With respect to exterior lighting, the Company stated that the primary purpose of exterior lighting is to provide safe working conditions on and around the facility structures

(id. at 27). The Company indicated that permanent exterior lighting likely would be located up to about the 100-foot level on the facility, or the approximate elevation where the HRSGs meet the 180-foot high stacks (id. at 9). The Company also stated that the FAA had determined that aviation lighting in the form of steady red beacons would be required at the top of the stacks (id. at 8). The Company stated that the final lighting design would attempt to minimize the visual impact of exterior lighting by using fixtures that would be oriented downward, and by using dark surfaces, where possible, to reduce reflectivity (id. at 27, 31; Exh. TF-AP-1).

As further mitigation for visual impacts, the Company stated that it would make certain off-site mitigation measures available to property owners in the vicinity of the proposed site (Exhs. HO-EV-7; HO-EV-14; Tr. 8, at 90-98, 100-107).[109] The Company stated that such mitigation typically would involve plantings of shrubs or trees to screen views of the facility, but could also include installation of window awnings or other reasonable and mutually agreeable measures (Tr. 8, at 104). The Company indicated that it would consider requests for off-site mitigation of visual impacts for locations up to one mile from the proposed site, and would review all such requests on a case-by-case basis (Tr. 8, at 103).

(2) Analysis

The record demonstrates that the proposed facility would be screened from view in most directions, but would have the potential for pronounced visual impacts along sections of Maple Street and at nearby residential and commercial properties located primarily to the east of the proposed site.[110] However, the Company's analysis indicates that views of the facility likely would be limited to the upper portions of the stacks as seen above existing trees at the majority of viewshed locations.

In addition, the record indicates that visible plumes of 50 meters or more in length would occur during approximately 50 percent of daylight hours. These plumes likely would be visible from areas where views of the facility structures themselves would be significantly limited or would not be visible.

With respect to the position of Franklin concerning the proposed use of steam augmentation and its associated visual impacts, the Siting Board is not persuaded that the increased visual impacts associated with steam augmentation would merit the dismissal of such technology as a design option for the proposed facility. The Company's plume visibility analysis assumed the base case scenario of just over 38 days per year of steam augmentation. Therefore, while steam augmentation is a contributing factor to plume visibility, it likely is not the determining factor for a majority of the 2571 hours (107 days) per year that visible plumes with lengths of 50 meters or more are expected. In addition, to the extent that steam augmentation would result in some additional hours of visible plumes, the Siting Board has recognized that the ability of the proposed facility to provide added capacity during peak load periods represents an important environmental advantage as it could reduce the need for new peaking units elsewhere, and therefore would avoid their associated site-specific impacts including the construction-related, land use and visual impacts of installing such units. For a comprehensive discussion of the proposed steam augmentation technology and related environmental impacts, see Section III.B.2.b, above.

With regard to the general appearance of the facility and related structures, the Company has indicated that in addressing issues such as building color, the effect of nighttime lighting at the site, and other related aesthetic concerns, it intends to seek consensus among its EPC contractor, local officials and other concerned parties in order to resolve such issues in a mutually satisfactory manner. The Siting Board agrees that it is appropriate for the Company to consider input from such groups on these issues to the extent possible, and encourages the Company to involve the various stakeholder groups in discussions of those final project design features, such as color, that would promote the integration of the proposed facility with its surroundings.

In three recent reviews, the Siting Board has required proponents of generating facilities to provide selective tree plantings in residential areas up to one mile from the proposed stack location to mitigate the visibility of the facility and the associated stack. Millennium Power Decision, EFSB 96-4 at 140; Dighton Power Decision, EFSB 96-3 at 47-48; Berkshire Power Decision, 4 DOMSB at 395.[111] Here, the Company has expressed a willingness to consider mitigation of visual impacts at locations within one mile of the proposed site where views of the facility are considered to be significant. The proposed mitigation would include provision of shrubs, trees, window awnings, or other reasonable forms of mitigation, if requested by local residents. Consistent with Siting Board precedent concerning the minimization of visual impacts, the Siting Board directs the Company to provide reasonable off-site mitigation of visual impacts, including shrubs, trees, window awnings or other mutually-agreeable measures, that would screen views of the proposed facility at properties along Maple Street, and at other locations within one mile of the proposed facility, as requested by residents or appropriate municipal officials.

In implementing its overall plan for off-site mitigation of visual impacts, the Company: (1) shall provide shrub and tree plantings, window awnings or other reasonable mitigation 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 Bellingham and Franklin, and to all potentially affected property owners in those communities, prior to the commencement of construction; (3) may limit requests for mitigation measures from local property owners and municipal officials to a specified period ending no less than six months after initial operation of the plant; (4) shall complete all agreed-upon mitigation measures within one year after completion of construction, or if based on a request filed after commencement of construction, within one year after such request; and (5) shall be responsible for the reasonable maintenance and replacement of plantings, as necessary, to ensure that healthy plantings become established.

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

d. Noise

(1) Description

The Company asserted that the projected noise impacts of the proposed facility at the proposed site would not adversely affect neighboring residences or properties and would be minimized in accordance with Siting Board standards of balancing environmental impacts consistent with minimizing costs (Exhs. BEL-1, at 6-74; BEL-15, at 8-1). The Company also asserted that noise impacts from the operation of the proposed facility would: (1) comply with the MDEP ten-decibel limit on noise increases at all residential receptors, as detailed in Policy 90-001 ("MDEP Standard"); and (2) cause no adverse impacts at the facility property lines based on the extent of buffer, the presence in some locations of non-residential land uses and zoning, and applicable federal guidelines for non-residential exposure (Exhs. BEL-1,

at 6-74; HO-EA-4.1, App. D at 13, 38; HO-EN-1.1; HO-EN-22; Tr. 13, at 83-85). The Company further stated that the worst-case noise impacts during on-site construction activity would be intermittent and temporary in nature, and that noise from construction traffic would be noticeable at nearby residences, but that such impacts would not be significantly greater than noise from existing traffic flow in the area[112] (Exh. BEL-1, at 6-88 to 6-94).

The Company stated that an increase of 3 decibels is the minimum increase in sound level that is generally perceptible to the human ear (Tr. 13, at 39-41). The Company stated that there are various measures of noise, and indicated that the MDEP Standard which limits allowable noise increases to 10 dBA is based on a relatively quiet measure of noise that essentially is the background sound level that is observed in the absence of louder, transient sounds (Exh. BEL-15, Vol. 1, at 8-3). The Company stated that for purposes of noise analysis in this case, the background level is defined as that level of noise that is exceeded

90 percent of the time ("L_{90}") (id. and at 8-4).

To define the noise impacts from operation of the proposed facility, the Company provided analyses of existing noise levels and expected noise increases resulting from construction and operation of the proposed facility (Exhs. BEL-1, at 6-88; HO-RR-77.1,

at 40). To establish existing background noise levels, the Company conducted surveys at four distinct locations having various distances and directions from the proposed site

(Exh. BEL-1, at 6-88). The Company stated that it selected the four noise monitoring locations ("NMLs") in order to obtain an adequate spatial representation of the ambient noise environment as a basis for modelling project-related noise increases at the nearest affected residences and property lines (id. at 6-86). The Company stated that the four NMLs were located as follows: (1) along Route 126 near the intersection of the existing electric transmission line corridor (NML-1), and representative of residences located approximately 2000 feet northwest of the proposed site; (2) on Maple Street near Pine Street (NML-2), representative of residential locations to the northeast of the site; (3) further south along Maple Street (NML-3), proximate to residences east of the site; and (4) on the proposed site itself, within the project footprint area (NML-4) (id.).

For each NML, the Company provided a set of noise measurements taken during 20-minute sampling periods which the Company indicated were representative of daytime and nighttime periods for both weekday and weekend conditions (Exh. BEL-15, Vol. 2, App. C.). The Company noted that for each NML, the quietest ambient levels were observed during the nighttime monitoring periods (Exh. BEL-1, at 6-88).

With respect to construction noise, the Company provided estimates of maximum levels of construction noise on site, and equivalent levels of such noise at the nearest residences, which the Company stated were located along Maple Street approximately 1400 feet east of the proposed facility footprint (Exh. HO-RR-77.1, at 14). The Company asserted that construction noise impacts are often transitory, and that the operation of diesel-powered heavy equipment is typically the major source of such noise (Exh. BEL-1, at 6-93; Tr. 13,

at 11-12). The Company estimated that maximum levels of construction noise at residences would be 60 dBA and that such levels likely would occur during the excavation and finishing phases of construction (Exh. HO-RR-77.1, at 16).[113] The Company asserted that during the ground clearing, foundations, and steel erection phases, maximum construction noise levels would range from 49 dBA to 56 dBA at the nearest residences (id.).

The Company also stated that cleaning and testing of the facility's pressurized systems would require steam blowouts during the final stages of construction and plant commissioning (Exh. TF-SB-1; Tr. 13, at 27-30). The Company indicated that it would use a patented "silent-blow" technique to attenuate noise from steam releases and that as a result, noise levels at the closest residences would be limited to 45 dBA during these events

(id.; Exh. F-RR-17).[114]

The Company indicated that mitigation of construction noise would include:

(1) complying with Federal regulations limiting truck noise, (2) limiting construction activities that are significant sources of noise to daytime hours, (3) ensuring that construction equipment manufacturers' normal sound muffling devices will be used and kept in good repair throughout the construction period, and (4) using silencing equipment to attenuate noise from steam-release events (Exhs. BEL-1, at 6-93; TF-SB-1; Tr. 13, at 19-22, 27-30).

To analyze the noise impacts of facility operation at residential and property line receptors, the Company provided estimates of facility noise, and combined facility noise and background noise, by receptor, for daytime and nighttime periods at five residential receptors and four property line receptors (Exh. HO-RR-77.1, at 40). Based on its analysis, the Company stated that during facility operation, daytime L_{90} increases would be zero to 5 dBA at residential receptors, and nighttime L_{90} increases would be 3 to 8 dBA, thereby satisfying the MDEP Standard at the residential receptors (id. at 41; Exh. HO-RR-78). The Company further stated that daytime L_{90} increases at the property lines of the proposed site would range from 8 to 16 dBA, with greater increases and exceedances at night[115] (Exhs. BEL-1, at 6-96 to 6-97; HO-EN-7; HO-EN-22; HO-RR-77.1, at 41).

With respect to noise impacts at the property lines of the proposed site, the Company stated that only daytime increases were considered where abutting lands were committed to commercial or industrial uses (Exh. HO-RR-77.1, at 40). The Company indicated that combined facility plus ambient noise would be 50 dBA at PL-3A, resulting in a daytime increase of 8 dBA at the east property line,[116] and would be 58 dBA at PL-2, resulting in a daytime increase of 16 dBA at the west property line (id.). The Company projected combined facility plus ambient noise levels of 52 dBA at PL-1, resulting in a daytime increase of 10 dBA at the northwest property line (id.). The Company stated that at location PL-4, the northeast property line, the proposed site abuts a 'Suburban' zoning district which allows residential uses and that nighttime increases therefore would be explicitly considered at that location (id. at 41). The Company stated that combined facility noise plus ambient at PL-4 would be 46 dBA, resulting in a nighttime increase of 10 dBA at this location (id.

at 40-41; see also Tr. 15, at 80-91).[117]

The Company concluded that, during the daytime, facility noise levels would produce exceedances of the 10-dBA limit along a portion of the west property line and that, therefore, the proposed facility would require a waiver of the MDEP Standard (Exh. HO-RR-78). Moreover, the Company stated that at night, facility noise would result in exceedances along the western and northern property lines and probably at the eastern property line[118] as well (Exh. HO-RR-77.1, at 41). The Company indicated that it would seek a property line waiver as part of the Air Plans review for the proposed facility, and maintained that it expected to receive such waiver from MDEP based on zoning and the presence of either wetlands or existing commercial uses that would preclude residential development on affected lands[119]

(id.; Exhs. HO-RR-77.1, at 41; HO-65.1 at 3-20; Company Brief at 157). In support of its contention, the Company cited prior instances in which MDEP had relaxed its standard based on a determination that present and future residential development would not be possible (Exh. HO-RR-65.1, at 3-20).

With respect to noise impacts at residential locations, the Company indicated that nighttime L_{90} levels at the nearest residences would range from 40 dBA to 44 dBA

(Exh. HO-RR-77.1, at 40). Based on its noise analysis, the Company identified receptor R-4B, a house located at 169 Maple Street, as the most affected residential location[120] (id.). The Company stated that nighttime L_{90} noise at this location was measured at 36 dBA and that facility noise would be 43 dBA (id.). The Company indicated that the resulting nighttime ambient plus facility noise would be 44 dBA, and would therefore result in an L_{90} increase of 8 dBA at this location (id.).

With respect to noise increases at R-4B, the Town of Franklin asserted that the Company mis-applied the available ambient noise data in its analysis of projected noise increases at that location (Franklin Reply Brief at 8). Franklin argued that, in calculating the expected L_{90} increase at R-4B, the Company should have used the 35 dBA level measured at NML-3 rather than the 36 dBA level measured at NML-2, because NML-3 is closer to R-4B than is NML-2 (id.). Franklin therefore asserted that, based on measured ambient levels at NML-3, the L_{90} increase expected at R-4B would be 9 dBA -- a level which would exceed the maximum 8 dBA increase allowed under the Bellingham Special Permit (id. at 9).

The Company also provided estimated day-night sound levels ("L_{dn}"),[121] with and without the proposed facility, for the various residential and property line receptors

(Exhs. HO-EN-17; HO-RR-75). The Company stated that, with the exception of location

R-1, on Route 126, where the existing L_{dn} is 64 dBA, L_{dn} levels at all modelled receptors were currently at or near the 55 dBA threshold described in the Levels Document[122]

(Exh. HO-RR-75). The Company estimated that at the most affected residence, location

R-4B, the existing L_{dn} is 55 dBA, the estimated facility L_{dn} would be 49 dBA, and the estimated combined L_{dn} would be 56 dBA (id.).

The Company also stated that, at the property lines of the proposed facility, the highest 24-hour equivalent noise level ("L_{eq}") would be 58 dBA at location PL-2, on the west side of the proposed site (Exhs. HO-RR-75; HO-RR-65.1, App. F, at 41). The Company indicated that this level would be 17 dBA less than the 75 dBA limit recommended by USEPA to protect hearing, and 27 dBA less than the threshold level of the Occupational Safety and Health Administration for worker exposure over an eight-hour day

(Exh. HO-RR-77.1, at 41).

The Company asserted that the proposed facility is being designed with careful consideration of measures to mitigate noise impacts to the surrounding community

(Exhs. BEL-1, at 6-74; HO-RR-77.1, at 42; Tr. 13, at 5 to 6). The Company stated that its final acoustical design for the proposed facility would consider the application of several noise mitigation technologies including: (1) muffling of the gas turbine exhaust stream;

(2) muffling in the gas turbine inlets, and enclosure of the inlet air ducts within the turbine buildings; (3) quiet air-cooled condensers and, if required, splitter mufflers to reduce fan noise; (4) heavier building walls to achieve adequate acoustic transmission loss for the turbine and gas compressor buildings; (5) acoustic louvers, if necessary, in ventilation intake openings in the east wall of the turbine building; (6) acoustic shrouds or partial enclosures around the exhaust ducts and HRSGs; and (7) silencing requirements for the circulating cooling water coolers (Exhs. BEL-1, at 6-74; HO-RR-77.1, at 42; Tr. 13, at 5 to 6,

48 to 59). By assuming a combination of the above measures in a facility design that would just meet the MDEP Standard at residential receptors, the Company derived a "baseline"

cost figure of $7.45 million for mitigation of noise impacts from the proposed facility

(Exh. HO-EN-19).

The Company stated that it modified the original design of the proposed facility to comply with requirements of the Special Permit from the Bellingham ZBA, which limits the nighttime L_{90} noise increase at residential receptors to 8 dBA (Exh. HO-RR-30.1, App. 1,

at 5; Tr. 13, at 5). The Company explained that additional reductions in facility noise at residences were accomplished by: (1) the acquisition of what would have been the closest residence, location R-4, to the east of the site; and (2) a modification to the plant layout involving the circulating cooling water coolers ("CCWCs") (Tr. 13, at 58-65). Specifically, the proposed facility would incorporate two smaller and quieter CCWCs instead of a single larger unit as initially proposed (id.). The Company stated that, pending the purchase of the residence in question, the incremental cost of the identified changes would be $150,000 for design changes involving the CCWCs, bringing the cost for noise mitigation at the proposed facility to $7.6 million (Exh. HO-RR-76).[123]

The Company offered testimony which described the conservative nature of its noise analyses, and stated that actual noise impacts from the proposed facility would be overestimated by the model due to worst-case assumptions with respect to: (1) meteorological conditions; (2) vegetative screening; and (3) ground reflectivity (Tr. 13, at 95-97). The Company's witness, Mr. Keast, stated that such conservatism likely would overstate the actual incremental L_{90} noise increase for some, and perhaps most of the time (id. at 97).

In response to requests from the Siting Board staff, the Company identified and considered the cost-effectiveness of various further measures for mitigation of noise impacts from the proposed facility, including design changes to the HRSGs or the ducts from the gas turbines to the HRSGs, the turbine building walls, and the air cooled condensers

(Exhs. HO-EN-15; HO-EN-19). The Company considered two specific combinations of measures: (1) an option that would reduce the maximum projected nighttime L_{90} increase to 7 dBA at the nearest residence ("Option 1"), at an additional cost of approximately $3.0 million beyond the baseline, representing a 40 percent cost increase for noise mitigation[124] (Exh. HO-RR-76 (Rev.)); and (2) an option that would reduce the maximum projected nighttime L_{90} increase at the property lines to 10 dBA ("Option 2"), at an additional cost of approximately $10.7 million above baseline, representing a 144 percent cost increase (id.). The Company noted that Option 2 would require more stringent silencing methods as well as further modification of the plant layout, and asserted that this option would be of limited benefit given that affected lands abutting the property lines could not support any residential use (Exh. HO-EN-15).

The Company stated that it did not propose to incorporate either of these noise mitigation options into the pre-construction design of the proposed facility, but maintained that additional noise mitigation measures would be available for incorporation during final facility design to complete the overall noise control package for the proposed facility

(Exh. HO-RR-77.1, at 42).

(2) Analysis

In past decisions, the Siting Board has reviewed the estimated noise impacts of proposed facilities for general consistency with applicable governmental regulations, including the MDEP's ten-dBA standard. Millennium Power Decision, EFSB 96-4 at 152; Berkshire Power Decision, 4 DOMSB at 403; Altresco-Pittsfield Decision, 17 DOMSC at 401. In addition, the Siting Board has considered the significance of expected noise increases which, although lower than 10 dBA, may adversely affect existing residences or other sensitive receptors. Millennium Power Decision, EFSB 96-4 at 152; Berkshire Power Decision,

4 DOMSB at 404; NEA Decision, 16 DOMSC at 402-403.

Here, the Company's analysis indicates that, for three residential receptors located to the north and east of the proposed site, facility operation would result in nighttime L_{90} increases of between six and eight dBA above existing ambient levels, which range from 35 to 36 dBA. During the day, facility operation would result in L_{90} increases of 5 dBA or less at all residential receptors. For the property line receptors to the northwest and west of the proposed site, which abut vacant industrially zoned land, nighttime L_{90} increases would be well above ten decibels and L_{90} increases would exceed the MDEP Standard along the west property line for the daytime period as well. At the east property line, a 3-dBA nighttime exceedance of the MDEP Standard is expected where the site abuts industrially zoned land which currently hosts a commercial use.

With respect to the proposed eight-dBA increase in nighttime L_{90} at the closest residence, the Siting Board notes that it previously considered and accepted a proposed increase of 8 dBA where nighttime ambient levels were low (31 to 33 dBA). Berkshire Power Decision, 4 DOMSB at 404. In that case, the Siting Board held that the proponent had demonstrated that the maximum contributions of facility noise to L_{dn} levels would be well below the USEPA 55-dBA guideline at residential receptors, and noted that overall noise levels were generally lower than the corresponding worst-case noise impacts in four other Siting Board reviews of gas-fired generating facilities. Id.

Here, nighttime ambient noise levels of 35 to 36 dBA are somewhat higher than in the Berkshire Power review. However, estimated nighttime noise levels with the proposed facility also would be generally lower than corresponding worst-case noise impacts in other Siting Board reviews of gas-fired generating facilities.[125]

The Siting Board agrees that ANP's proposed eight-dBA nighttime L_{90} increase would be consistent with increases accepted in recent reviews, and recognizes that the Company achieved such levels by undertaking specific noise mitigation efforts, including (1) appending additional buffering lands to its proposed site, and (2) reconfiguring certain noise producing components of the facility to reduce off-site noise impacts.

With respect to the Town of Franklin's argument that the ambient noise level at R-4B is better represented by NML-3 than by NML-2, the Siting Board notes that although R-4B is situated generally between NML-2 and NML-3,[126] the 35 dBA ambient level measured at NML-3 may be the more appropriate level to use in calculating the estimated L_{90} increase at R-4B because its use would result in a more conservative estimate of impacts, and thereby would effectively capture in the analysis, the likely "worst-case" impact at that location. The Siting Board further addresses this issue, below, in its discussion of estimated (i.e., modelled) versus actual noise increases.

With respect to impacts of the proposed facility on L_{dn} noise, the Company has focused primarily on noise from the proposed facility alone, rather than on combined facility plus ambient 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 55 dBA USEPA guideline -- and based on that concern, limited L_{90} increases to no greater than

5 dBA. 1993 BECo Decision, 1 DOMSB at 108, 109, 114. Here the existing residential L_{dn} levels estimated by the Company are at or near the USEPA guideline at all residential receptors, except the relatively distant location R-1 on Route 126. Moreover, the Company has provided estimates showing that future L_{dn} levels would remain essentially unchanged with operation of the proposed facility. The Siting Board notes that here, as in other recent facility reviews where relatively quiet background noise levels were present at night, estimated contributions from the facility itself to overall residential L_{dn} levels would be significantly less than 55 dBA.

With respect to noise impacts at the site property lines, the record indicates that daytime L_{90} increases of up to 16 dBA would occur on vacant industrially zoned lands which abut the northwest and west property lines. The Company has demonstrated that the affected areas are not zoned to allow residential use, and also asserts that noise levels in such areas would comply with OSHA regulations for worker safety and USEPA guidelines to protect hearing in non-residential areas. In previous reviews, the Siting Board has identified acquisition of additional lands or easements in affected areas as a means to mitigate off-site noise impacts. Berkshire Power Decision, 4 DOMSB at 405. The Siting Board notes that here, the proposed site is larger than several other generating facility sites recently reviewed by the Board, and that lands under the control of the proponent have been used with generally good effect to buffer abutting lands to the south and east of the project from property line noise increases that might otherwise have approached the MDEP ten-decibel standard.[127]

The record includes evidence regarding two options to further mitigate noise impacts from operation of the proposed facility; Option 1 which would reduce maximum nighttime L_{90} increases by one decibel to 7 dBA at the nearest residence, at a cost of $3.0 million; and Option 2, which would reduce property line impacts to meet the MDEP Standard, at a cost of $10.7 million. However, ANP-Bellingham has not proposed to implement options to further mitigate noise impacts from operation of the proposed facility, citing cost and limited effectiveness.

The Siting Board has found in several prior cases that incremental mitigation to reduce L_{90} noise impacts at residences was cost-justified. Millennium Power Decision, EFSB 96-4

at 156; Berkshire Power Decision, 4 DOMSB at 405, 442; Silver City Decision,

3 DOMSB at 367, 413. In Silver City, the Siting Board addressed proposed L_{90} increases of 10 dBA at affected residential receptors, and considered the cost-effectiveness of incremental mitigation measures that would result in decreased L_{90} impacts at those locations. Silver City Decision, 3 DOMSB at 357, 413. Here, the proponent already has taken steps to reduce the maximum L_{90} increase at a residential receptor from 10 dBA to 8 dBA, at an incremental cost of $150,000 plus the acquisition cost of the nearest residence (R-4). In addition, many of the Siting Board's prior decisions did not involve proposals for air-cooled technology, which, as the Siting Board previously has noted, can limit options for cost-effective noise mitigation, but materially reduces other environmental impacts relating to water consumption, the visual impact of plumes from water cooling towers, and fogging and icing impacts from those plumes. Dighton Power Decision, EFSB 96-3 at 57; Berkshire Power Decision,

4 DOMSB at 345, 441. Finally, the record indicates that the incremental cost of reducing the L_{90} noise increase at the most affected residence to 7 dBA would be $3.0 million. Given that the maximum increase in L_{90} noise at residences already would be 2 dBA less than the MDEP Standard, and L_{dn} levels would remain close to the 55 dBA USEPA guideline, the record does not support incurring the added cost to achieve a further noise reduction of one decibel.

Consequently, the Siting Board finds that the incremental noise reductions that could be achieved through the incorporation of additional pre-construction mitigation measures in the project design would not result in cost-effective noise reduction benefits to the neighbors of the proposed facility, and therefore would not be consistent with minimizing costs. We also note that, consistent with the Siting Board's statutory mandate to minimize environmental impacts consistent with minimizing costs, it is appropriate to consider the overall environmental impact of the facility, and that the limited cost-effectiveness of further noise mitigation measures is in part attributable to the planned use of air-cooled technology, which the Siting Board previously has recognized to be of substantial and offsetting environmental benefit due to greatly diminished water consumption. Dighton Power Decision, EFSB 96-3 at 57; Berkshire Power Decision, 4 DOMSB at 345,441. The Siting Board therefore will not require additional noise mitigation beyond that already proposed by the Company.

Accordingly, the Siting Board finds that, with the implementation of proposed mitigation, the environmental impacts of the proposed facility with respect to operational noise would be minimized, consistent with minimizing cost.

With respect to construction noise impacts, the Siting Board agrees that adherence to the Company's proposed construction site practices concerning machinery and hours of operation, combined with the proposed mitigation of steam release events, would minimize construction related noise impacts. The Siting Board notes that the proposed steps would be consistent with approaches to construction noise mitigation that it has reviewed in recent generating facility cases. Therefore, the Siting Board finds that the environmental impacts of the proposed facility with respect to construction noise would be minimized.

Accordingly, the Siting Board finds that, with the implementation of proposed mitigation, the environmental impacts of the proposed facility with respect to noise would be minimized, consistent with minimizing cost.

Notwithstanding the foregoing acceptance of the proposed project design with respect to noise impacts, the Siting Board recognizes that noise issues, and specifically the accuracy of noise projections, are frequently a subject of particular concern to neighboring residents. Therefore, in order to alleviate public concern in this area, the Siting Board also finds that it would be appropriate to measure the noise impacts of operation of the proposed facility to verify the actual extent of L_{90} noise increases, and the degree of consistency with the 8.0 dBA maximum at residential receptors.[128] The Siting Board believes that noise monitoring in this case would serve two purposes: first, it would address concerns raised by intervenors regarding uncertainties inherent in noise modelling by confirming that the Company has actually achieved its projected noise levels; and second, it would provide information as to the accuracy of noise modelling that would be useful to the Siting Board in conducting future generating facility reviews.

Accordingly, ANP is directed to develop and implement a noise testing protocol to determine, at a date within one year of entering commercial operation, the actual L_{90} noise increases at the Maple Street residential receptors.[129] Such protocol should be consistent with the type of protocol used for testing compliance with the MDEP Standard, and should be conducted at, or as close as is practicable to, the Maple Street receptor locations identified in the Company's filing.

The Company is directed to provide a report to the Siting Board and the Town of Bellingham ZBA including: (a) a description of its noise testing protocol; (b) the results of its noise testing; (c) an assessment of any operating or maintenance factors, including weather conditions or equipment problems, that may have contributed to the result; (d) records of any complaints received concerning noise from the facility since start-up; and (e) any steps the Company plans to take, or has considered taking, to reduce plant noise.

If noise testing indicates an actual L_{90} noise increase of greater than 8.0 dBA, the Company is further directed to assess options for such noise mitigation as would be required to bring the facility into compliance with the 8.0 dBA increase accepted by the Siting Board and the Town of Bellingham ZBA.

e. Traffic

(1) Description

The Company asserted that the construction and operation of the proposed facility at its proposed site would have negligible impacts on local traffic conditions (Exh. BEL-1,

at 6-120). In support of its assertion, the Company provided traffic volume data for existing traffic conditions, and modelled future traffic conditions, with and without the proposed facility. The Company stated that its analysis included expected trip generation that would be attributable to the proposed facility, and estimated the impacts that would result from both facility construction and operation (id. at 6-98).

The Company indicated that existing peak commuter traffic periods in the vicinity of the proposed site are 7:00 a.m. to 8:00 a.m. and 4:45 p.m. to 5:45 p.m. (Exh. BEL-15,

Vol. 1, at 5-2). The Company stated that, to estimate the traffic impacts on area roadways of construction at the proposed site, it assumed that all of the first shift of civil/construction workers would arrive during the morning peak period, and that all of those workers would depart during the evening peak (id.; Exh. BEL-1, at 6-108).[130] The Company indicated that these assumptions would result in a conservative estimate of traffic impacts because, in actuality, shift changes at the proposed site would be generally outside of local peak hours (Exh. BEL-15, Vol. 1, at 5-2). The Company provided information regarding its planned work schedule during construction of the proposed facility, and indicated that the most intensive construction activity at the site would occur from months 12 to 17 of the planned 20.5 month construction schedule.[131] The Company stated that the maximum number of construction workers employed on the site at any one time could be up to 800 persons (id.).[132] The Company presented a comparison of expected peak-hour levels of service ("LOS")[133] with and without the proposed facility for the two gateway intersections to the proposed site: (1) Route 126 and Maple Street to the north of the proposed site; and

(2) Route 140 and Maple Street to the south of the proposed site (Exh. BEL-1, at 6-98;

BEL-15, Vol. 1, at 5-1). With respect to existing traffic flow conditions at the two gateway intersections, the Company stated that during peak commuter periods, each of these unsignalized intersections operate with delays of greater than 120 seconds, and therefore are rated at LOS F for those periods (Exh. BEL-1, at 6-113).

Based on its analysis of construction traffic volumes, the Company estimated that for the morning peak period in 1999, construction-related traffic would constitute between seven and 14 percent of total intersection volumes at the two gateway intersections

(Exh. HO-ET-7). For the 1999 evening peak period, the Company estimated that between three and ten percent of total intersection volume at the gateway intersections would be attributable to construction activity at the proposed facility (id.).[134]

The Company also assessed peak hour LOS for the unsignalized intersection of the proposed site access driveway with Maple Street and projected that traffic conditions during construction would be acceptable (LOS B) for both morning and afternoon peak periods

(Exh. BEL-1, at 6-109).[135]

The Company stated that it recognized that construction of the proposed facility would add additional traffic volume to areas that currently experience deficient traffic flow, and that it would mitigate such impacts by attempting to schedule shift changes so as to avoid local peak traffic periods, and by arranging with state and local authorities to provide uniformed officer controls at the affected intersections during the morning and afternoon shift changes (Exh. BEL-1, at 6-113). As an additional mitigating factor, the Company noted that a new commercial enterprise, Charles River Place ("CRP"), was currently under development in Bellingham near the junction of Route 126 and I-495, and that the proponent of that project had agreed to signalize the Maple Street/Route 126 intersection as mitigation for traffic impacts (id. at 6-105; HO-ET-5). The Company stated that, once signalized, traffic flow at the Maple Street/Route 126 intersection would be improved to LOS B during the a.m. peak hour, and LOS C during the p.m. peak hour (Exhs. BEL-1, at 6-113; HO-ET-9.1).[136]

The Company indicated that, in addition to employee worker trips, there would be 45 delivery vehicle round trips per day during the peak construction period (Exh. BEL-15,

Vol. 1, at 5-2).[137] The Company stated that deliveries of very large equipment and plant components would be scheduled for off-peak times and that the Company would coordinate such deliveries with state and local officials (Exh. BEL-1, at 6-108; Tr. 8, at 179-186). The Company stated that its EPC contractor, ABB, would be responsible for conducting road and bridge surveys to ascertain that adequate roadway widths, turning areas and bridge capacities would be present along its proposed delivery route (Exh. BEL-15, Vol. 1, at 5-7; Tr. 8,

at 146-149). The Company indicated that the Maple Street/I-495 bridge would be the subject of a capacity study and that the Route 140/Maple Street intersection might require widening, but that a determination of the need for such roadway improvements would not be made until ABB completed its study prior to final placement of the EPC contract (id.;

Exh. BCC-W-7).[138]

The Town of Franklin argued that because the ABB traffic study for the proposed project was incomplete, the Company had not adequately identified or described the traffic impacts to local roadways, including those in the Town of Franklin (Franklin Brief at 24). Franklin therefore asserted that the Company could not demonstrate that the traffic impacts of the proposed project would be minimized (id.). The Town of Franklin also expressed concerns that although roadways in Franklin, including Route 140, would figure prominently in the Company's plans to deliver equipment and labor to the proposed site, the Company had not yet approached the town regarding the matter (id. at 3, 23). However, the Company asserted that detailed permitting for traffic impacts typically occurs after the completion of the Siting Board's review and argued, citing Millennium and Berkshire, that the Siting Board previously had conditionally approved generating projects for which comprehensive traffic impact studies were pending (Company Reply Brief at 19).

In the process of developing approaches to mitigation for traffic as well as for other impacts, the Company stated its intention to form a liaison group consisting of local officials and residents that could include affected persons from Bellingham as well as from abutting towns, including the Town of Franklin (Tr. 8, at 81, 84). With respect to traffic impacts in particular, the Company stated that such a group likely would include representatives from each town through which traffic relating to project deliveries would travel (Tr. 9, at 22, 24).

With respect to traffic impacts from the proposed facility during operation, the Company stated that once the facility is fully operational, 16 employees would be on site during the day shift, and four employees would be on site during the night shift (Exh. BEL-1, at 6-117). The Company stated that, based on conservative projections of traffic impacts during facility operation, the proposed facility would have insignificant impacts on local traffic conditions, and that vehicle trips related to the proposed facility would constitute less than one percent of peak hour volumes at the gateway intersections (id. at 6-120). The Company asserted that no additional traffic mitigation would be necessary during operational lifetime of the proposed facility due to the expected low number of trips (id.).

(2) Analysis

The record indicates that there would be no change in LOS classification at the two identified gateway intersections near the proposed site as a result of either construction or operation of the proposed facility. However, the Siting Board notes that the intersections of Maple Street with both Route 126 and Route 140 currently exhibit poor traffic flow (LOS F) at peak travel times. Consequently, the Siting Board is concerned that although the LOS designation of the gateway intersections would not change with construction and operation of the proposed facility, the existing congestion at these already failing intersections likely would be exacerbated by traffic activity associated with the proposed project, particularly during the months of peak construction activity at the site.

To minimize traffic impacts from construction of the proposed facility, the Company has indicated that it would attempt to schedule shift changes outside of the identified local peak traffic hours, and would coordinate with state and local authorities to place uniformed officer controls at the intersection of Maple Street and Route 126, and the intersection of Maple Street and Route 140 during periods of maximum traffic flows relating to the proposed facility. The Siting Board agrees that such efforts would be consistent with those proposed and accepted in previous reviews of generating facilities.

The Company plans to schedule delivery of very large equipment and plant components for off-peak hours and intends to coordinate such deliveries with the appropriate state and local officials. However, the Siting Board is concerned that, regardless of scheduling, delivery of materials and equipment to the project site could affect traffic flow on area roadways, including Route 140. The Siting Board also notes that the Company is presently unable to identify a confirmed route for deliveries of very large plant components. We are concerned that if significant improvements to area roadways or bridges should be required to accommodate such deliveries, additional traffic impacts likely would result.

Therefore, the Siting Board directs ANP, in consultation with the MHD and the Towns of Bellingham, Franklin, Wrentham and Foxborough, to develop and implement a traffic mitigation plan which addresses intersection control, scheduling, and roadway and bridge construction.[139] With respect to intersection control, the Company is directed to coordinate with the appropriate authorities to place officer controls at unsignalized gateway intersections, and at other areas of concern as necessary, during the construction period. With respect to scheduling, the Company is directed to schedule, to the maximum extent practicable, arrivals and departures of construction related traffic, including but not limited to construction labor, deliveries of materials, equipment, and plant components, in a manner so as to avoid daily peak travel periods in affected areas. Such plans also should include steps to minimize traffic impacts associated with any roadway or bridge modifications, or other improvements, that may be required to effect delivery of large plant components.

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

f. Safety

With respect to safety issues, ANP stated that to help insure safety at the proposed facility it would: (a) adhere to good engineering practice and comply with federal, state, and local regulations in its design, construction and operation activities; (b) require contractors to have programs in place to ensure compliance with applicable safety and health standards during construction; (c) incorporate into its construction contract provisions that require contractors to adhere to safety and health requirements; and (d) continually monitor operations on a regular basis (Exh. BEL-15, at 3-17; Tr.14, at 166).

In addition, the Company stated it would include within the facility the following design features to help insure safety: (a) containment basins or dikes for all hazardous material storage areas; (b) automatic shutdown systems with backup power supply for turbines and fuel supply systems; (c) emergency lighting; (d) adequate access for fire fighting vehicles and equipment; (e) fire retardant building materials and a self-sufficient fire protection system; and (f) fencing around the proposed site to prevent unauthorized individuals from gaining access to the facility (Exh. BEL-15, at 3-17 to 3-18).

(1) Materials Handling and Storage

ANP indicated it would store aqueous ammonia on site in two 14,000 gallon tanks, sitting side by side, and surrounded by a reinforced concrete dike (Exh. BEL-15, at 3-17). The Company stated that the transfer of ammonia from delivery vehicles would occur within a concrete diked containment area (id.; Tr.14, at 172). The Company also agreed to construct a single-roofed containment building enclosing the diked area and the dikes, but noted it would not completely seal the building in order to prevent pressure buildup

(Exh. HO-RR-84; Tr. 11, at 77 to 78; Tr.14, at 174 to 176).

The Company provided computer modeling data which shows that the concentrations at the fence line from an ammonia spill would be 42 ppm after 30 minutes and 32 ppm after one hour, even without the containment building (Exh. HO-ES-1.1, at 2). The Company noted that these concentrations are below the Immediately Dangerous to Life or Health ("IDLH") threshold of 500 ppm (Exh. HO-RR-84). The Company stated that construction of the containment building would decrease the rate of evaporation of ammonia in the event of a spill and, depending on wind conditions at the time of the accident, could help reduce the concentration of ammonia at the fence line (Exh. HO-ES-1.1 at 2).[140]

The Company asserted that ammonia would be the only chemical delivered to the site via bulk shipments (Exh. HO-ES-6). All other chemicals would be delivered in small shipments via common carrier in approved Department of Transportation ("DOT") containers (id.). In addition, the Company stated that it would store chemicals on site in their DOT approved shipping containers whenever possible, and that the operators of the facility would store hazardous materials in a manner consistent with the Specific Material's Safety Data Sheet precautions (id.).

(2) Fogging and Icing

The Company used a fog model to assess whether the facility would cause ground level fogging or icing either during normal operations or during steam augmentation

(Exh. HO-ES-8; Tr. 15, at 8-9). The modeling results indicated that fogging and icing would not occur under either scenario (Exh. HO-ES-8; Tr. 15, at 8-9).

(3) Emergency Response Plan

The Company indicated that it would develop an Emergency Response Plan ("ERP") and a Spill Prevention, Control and Countermeasure Plan ("SPCCP") similar to those found acceptable in previous Siting Board decisions (Exh. HO-ES-3).[141] The Company also stated that it would develop a separate contingency plan for the storage and handling of hazardous materials (Tr. 14, at 203). The Company indicated that it would develop these plans when the plant is completed (Exh. HO-ES-10; Company Brief at 171). In addition, the Company asserted that personnel trained in the ERP and SPCCP procedures would be on site at all times and that emergency response and spill prevention equipment would be continuously maintained at the power plant site (Exh. HO-ES-10).

(4) Analysis

The record demonstrates that the Company will manage, transport and store aqueous ammonia, and all other non-fuel chemicals, in accordance with applicable public and occupational safety and health standards. In particular, the Company's modeling results show that aqueous ammonia concentrations for the proposed facility, even in the event of a worst-case spill, would not exceed the IDLH standard at sensitive receptors located at or beyond the fence line. In addition, the Company has agreed to further reduce ammonia concentrations by constructing a containment building around the dikes.

With regard to fogging, the record demonstrates that there will be no ground level fogging or icing resulting from cooling tower operations or steam augmentation.

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. The Siting Board also notes that the Company intends to develop emergency procedures and response plans similar to those found acceptable in previous Siting Board decisions. The Siting Board encourages the Company to have applicable elements of its emergency response plan completed and filed with the Town before construction begins in order to cover possible contingencies related to construction accidents. In addition, the Siting Board encourages the Company to have trained personnel and equipment ready to address construction-related contingencies.

Accordingly, the Siting Board finds that, with the implementation of the safety measures described by the Company, the environmental impacts of the proposed facility would be minimized with respect to safety.

g. Electric and Magnetic Fields[142]

(1) Description

ANP indicated that operation of the proposed facility would produce magnetic fields associated with (1) the two new 345 kV lines which would interconnect the proposed project with transmission lines owned by New England Power Company ("NEPCo"), and

(2) increased power flows on certain existing transmission lines (Exhs. BEL-15, at 9-8 to

9-13).[143] The Company indicated that the proposed facility would interconnect with NEPCo's 345 kV 303 line, which shares a right-of-way extending from the Beaver Pond substation to the West Medway substation with a 115 kV transmission line designated as the C-129 line ("303/C-129 ROW") (id. at 9-5).

The Company asserted that EMF levels from the 150 foot interconnect lines, which would be located entirely on the proposed site, would be negligible at the site boundary

(Exh. BEL-15, at 9-5, 9-11; Exh. BEL 12.2). With respect to impacts on the transmission system along the 303/C-129 ROW, the Company indicated that the proposed project's operation would primarily affect power flow and associated magnetic fields extending north from the interconnection point to West Medway substation, although it also would affect power flows extending south to the Beaver Pond and Brayton Point substations (Exh. BEL 15, at 9-5). The Company explained that, under most regional generation dispatch scenarios, the proposed project would add approximately 500 megavolt-amperes of power flow to the preexisting flow on the 303 line north to West Medway substation (Exh. HO-RR-89S2, at 3). The Company also indicated that some shifts in preexisting power flow would occur, resulting in some increase in power flow on the adjacent C-129 line (Exh. HO-RR-32).

ANP provided calculations of magnetic field levels along the 303/C-129 ROW

north of the interconnection point, both with and without operation of the proposed facility (Exhs. HO-RR-31; HO-RR-32). These calculations indicated that, under worst-case (light load) conditions, operation of the proposed facility would increase maximum magnetic field levels on the eastern edge of the ROW by approximately 18 milligauss ("mG"), to approximately 68 mG, and on the western edge of the ROW by 7 mG to approximately

13 mG (id.). The Company noted that these levels would be well below the 85 mG threshold which the Siting Board has previously recognized (Company Brief at 176). The Company added that, along the affected ROW segment north of the interconnection point, there are nine residences at or near the eastern edge of the ROW and three residences at or near the western edge of the ROW (Exhs. HO-EE-6, HO-EE-6.1).

ANP also provided information from the project interconnection study regarding transmission upgrades that may be required as a result of the proposed project, either alone or in combination with other projects (Exhs. HO-EE-14.1; HO-RR-89S2). The Company stated that reconductoring of the NEPCo 303 line between the site and West Medway substation would be required to accommodate the full 580 MW output of the proposed project

(Exhs. HO-RR-27; HO-RR-89S2).

In addition, the Company indicated that, given the tendency for power to flow north on area transmission lines toward the West Medway substation, much of the project output would be carried beyond that point via various interconnecting regional transmission routes (Exh. HO-RR-89S2, at 3). The Company stated that combined increases in power flows from its proposed Bellingham and Blackstone projects would clearly require reconductoring segments of a 115 kV transmission line between the West Walpole and Needham substations, and might require reconductoring a 345 kV line in central Massachusetts and two additional 115 kV line segments in Rhode Island and central Massachusetts (id. at 5-10). In addition, if power flows from these two projects are considered in conjunction with the output of a

477 MW expansion of the Brayton Point generating station,[144] the project interconnection study indicates: (1) the need to reconductor a 345 kV line and three 115 kV line segments in eastern and central Massachusetts; and (2) the possible need to reconductor two additional 345 kV lines in central Massachusetts (Exh. HO-RR-27.1, at 23 to 24).

At the request of the Siting Board, the Company identified design measures that could be implemented as part of a transmission upgrade to reduce magnetic fields, and assessed the likelihood that these measures could be incorporated into the five upgrades that either would or might be required to interconnect either the proposed project alone, or both the ANP Bellingham and ANP Blackstone projects (Exhs. HO-RR-89S; HO-RR-89S2). The

identified design measures included: (1) changing the phasing of adjacent transmission circuits; (2) changing the spacing of conductors on existing transmission structures; and

(3) resuspending the conductors on structures of different design (Exh. HO-RR-89S).

The Company indicated that all the potential transmission upgrades likely would be accomplished by installing larger conductors on existing H-frame transmission structures (Exh. HO-RR-89S2). The Company therefore concluded that changes to either the conductor spacing or the structure design likely would not be feasible due to cost or engineering constraints (id.). The Company indicated that the remaining design measure -- changing the phasing of adjacent circuits -- may be applicable for the four known and potential upgrades which would involve lines on ROWs with multiple circuits (id. at 2-8).[145] The Company stated that it expects NEPCo, which would be responsible for those four transmission upgrades, to complete detailed facility designs by August 1, 1998 (id.). The Company indicated that it would encourage NEPCo and other transmission providers to incorporate prudent, cost-effective design measures that may reduce magnetic fields into any transmission upgrades required for the proposed project (Company Brief at 177, Exh. HO-RR-89S2,

at 2-8).

(2) Analysis

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

Although consistent with edge-of-ROW levels previously accepted by the Siting Board, the estimated maximum magnetic fields along the 303/C-129 ROW with operation of the proposed facility -- approximately 68 mG at the eastern edge of the ROW and the nearest residence -- are among the highest ever reviewed by the Siting Board, and represent a sizable increase above existing levels of approximately 50 mG.

The record does not include estimates of magnetic field changes related to the impact of project operation on sections of the transmission system other than the 303 and C-129 lines. The record does include evidence of the cumulative effect on power flow of adding approximately 1100 to 1500 MW of output from new projects, including the proposed project, interconnected to two 345 kV transmission lines extending south from the West Medway substation. Under most dispatch scenarios, much of this added output would be exported north or west from the West Medway substation, predominantly via key lines extending northwest to Millbury substation and beyond. A number of upgrades may be required along principal ROWs in central Massachusetts to accommodate the added output.

The Siting Board notes that, in past transmission line reviews, applicants have recognized that some members of the public are concerned about magnetic fields and for that reason, the applicants have incorporated design features into proposed transmission lines that would reduce magnetic fields at a low additional cost or no additional cost. See e.g., NEPCo Uxbridge Decision, 4 DOMSB at 148. The Siting Board has held that, as part of pursuing interconnection plans that require upgrades to the regional transmission system, generating facility applicants also should work with transmission providers to seek inclusion of practical and cost-effective transmission designs to minimize magnetic field levels along affected ROWs. Millennium Power Decision, EFSB 96-4, at 176; Berkshire Power Decision,

4 DOMSB at 421; Silver City Decision, 3 DOMSB at 353-354.

Here, the Siting Board notes that the Company has committed to request that NEPCo and other transmission providers consider potential magnetic field reductions and costs, as well as the feasibility, environmental impact and safety implications of different electrical phasing arrangements, in selecting the final design for required upgrades. However, the Company has indicated that cost and engineering considerations likely would lead the transmission provider to reuse, rather than replace, existing transmission structures, thus precluding changes to conductor spacing or structure design as part of the transmission upgrades. This limitation may significantly reduce opportunities to minimize magnetic fields.

In addressing a similar situation in a past review, the Siting Board encouraged consideration of alternative reconductoring designs on a localized basis, where residences are concentrated near an affected ROW, rather than for the entire circuit length requiring reconductoring. Millennium Power Decision, EFSB 96-4, at 176-177. While we recognize that significant costs could be involved in modifying or replacing even a few existing transmission structures, the Siting Board encourages ANP to work with NEPCo and other transmission providers to determine whether very localized changes to conductor spacing or structure design could provide a cost-effective means of minimizing project-related EMF increases near concentrations of residences.[146]

The Siting Board notes that the record in this case presents a broader range of EMF and transmission issues than in past Siting Board reviews of generating facilities. This is due in part to the higher output (580 MW) of the proposed facility, and in part to the cumulative nature of the transmission study submitted in this case, which reflects not just the proposed facility but also the proposed ANP Blackstone facility and the hypothetical expansion of the Brayton Point generating station. In addition, as has been the case in a number of previous reviews, the record is not complete as to the extent or design of required transmission upgrades and the related ability to minimize EMF impacts.[147]

The Company's commitment to work with NEPCo and other transmission providers is similar to that of previous generating facility applicants, and the Siting Board accepts that approach as meeting its standard of review for EMF. However, given the broad scale of transmission upgrades potentially required for this and neighboring projects, and the associated significance of both the projects and the transmission upgrades for EMF levels in the region, the Siting Board seeks to remain informed as to the progress and outcome of transmission upgrade designs related to interconnecting the proposed project. Therefore, the Siting Board directs ANP to provide to the Siting Board with an update on the extent and design of required transmission upgrades, and the measures incorporated into the transmission upgrade designs to minimize magnetic field impacts, at such time as ANP reaches final agreement with all transmission providers regarding transmission upgrades.

Accordingly, the Siting Board finds that, (a) with the Company's pursuit of designs for upgrading the 303 line and other affected transmission lines that the Company and the transmission providers determine would best limit magnetic field increases at affected residences, and also be practical and cost-effective, and (b) with the Company's compliance with the condition to provide an update on required transmission upgrades and measures to minimize magnetic fields, the environmental impacts of the proposed facility would be minimized with respect to EMF impacts.

h. Land Use

(1) Description

The Company asserted that the development of the ANP Bellingham Energy Project at the proposed site would be compatible with current land use characteristics and zoning for the site, and would be consistent with the development objectives of the Town of Bellingham and the region (Exh. BEL-1, at 6-63). The Company further asserted that the proposed project would be compatible with surrounding uses and would be an economic benefit to the region during both construction and operation of the facility (id. at 6-64, 6-67).

The Company stated that the proposed facility is to be constructed in an industrial zone located west of Maple Street in Bellingham (Exh. BEL-1, at 6-64). The Company indicated that the 125-acre site is currently undeveloped and is generally wooded, except in the eastern portion where it is traversed by a 325 foot wide electric transmission line ROW (id. at 6-122). The Company noted that two high voltage transmission facilities, owned by NEP, are located within the existing ROW: the C-129 line (115 kV), and the 303 line

(345 kV) (id.).

The Company stated that the proposed facility layout would require clearing of an approximately 20 acre upland portion of the site that is currently wooded (Exhs. BEL-1,

at 6-58; HO-EL-10; Tr. 15, at 56). The Company also indicated that approximately seven additional acres along the western edge of the NEP ROW, and adjacent to the proposed facility footprint, would be temporarily cleared to facilitate construction activity and to provide space for construction parking and materials laydown areas (id. at 6-58; Exh. EC-2 (Rev.); Tr. 15, at 56-58, 99-103). The Company indicated that, subject to agreements with NEP and the Bellingham Conservation Commission, it intended to replant certain cleared portions of the site after completing construction of the proposed facility, including the built-up slopes to the southwest of the plant, and portions of the NEP ROW, except in the immediate vicinity of the electrical tie-in for the project (Exhs. HO-EL-10; HO-EC-2 (Rev.); Tr. 15, at 57-58, 99-103).

The Company described the land uses contiguous to the proposed site as the aforementioned utility easement and commercial and residential uses to the east and south, vacant land including wetlands associated with the Charles River to the north, and an interstate highway ("I-495") to the west (Exh. BEL-1, at 6-63). The Company also indicated that new commercial development, including a cinema complex, was under construction to the northwest of the site near the intersection of I-495 and Route 126 (id.; Exh. HO-RR-44). Based on 1991 land use data available from the Massachusetts Geographic Information System Office ("MassGIS"), the Company estimated that 77 percent of the area within a one-mile radius of the proposed site is open or agricultural land, 18 percent is devoted to residential uses, and 5 percent is used for commercial or industrial purposes, including I-495 (Exh. HO-EL-3). Within a half-mile radius of the proposed site, the Company estimated that 79 percent of the land is open or agricultural, 14 percent is residential, and 7 percent is used for industrial or commercial purposes (id.).[148]

The Company stated that its proposed facility would be buffered from nearby uses by distance and natural features, including wetlands, as well as by surrounding developed uses, including I-495 and the NEP ROW (Exh. BEL-1, at 5-58, 5-63). Furthermore, the

Company indicated that, pursuant to its PILOT agreement with the Town of Bellingham (See

Exh. HO-V-23.1), it would convey to the town as "restricted open space" approximately 92 undeveloped acres of the site that would then be preserved and maintained by the Town as conservation land (Exhs. BEL-15, Vol. 1, at 10-24; HO-EL-15; HO-V-23; HO-EL-17).

The Company indicated that most of the residential uses in the vicinity of the site are located along Maple Street and adjoining streets to the east and north of the site which extend further easterly across the town boundary into the Town of Franklin (Exh. BEL-1, at 6-63 to 6-65). The Company stated that presently, the closest residence is located 330 feet to the east of project property line; however, the Company explained that the residence is located on property that would be acquired by the Company to accommodate its proposed access road (Exhs. HO-EL-2; BEL-12.2; Tr. 15, at 72 to 73). The Company therefore asserted that, post construction, the closest residence would be located on the west side of Maple Street approximately 780 feet from the nearest facility fenceline, and approximately 470 feet south of the nearest project feature, a storm water basin located adjacent to the intersection of the proposed facility access driveway with Maple Street (Exh. HO-RR-85). The Company added that, as mitigation for potential impacts to residential property values in the vicinity of the proposed facility, it had offered a Property Compensation Program that would be available to residents within one half mile of the proposed site (Company Brief at 179).

The Company stated that it identified a total of 53 residences within one half mile of the proposed facility, and that it identified 322 residences that would be located within one mile of the project (Exh. HO-EL-2).[149] The Company indicated that the nearest undeveloped land that potentially would be available for residential development would be located 780 feet to the northeast of the proposed project's fenceline (Exh. HO-EL-4).[150]

Mr. Brady, a witness presented by intervenor Goulart, testified regarding his own land use analysis which found a significantly larger number of Franklin residences located within one mile of the proposed facility. Mr. Brady stated that the analysis used property assessment data supplied by the Town of Franklin to determine that 671 Franklin residences would be located within one mile of the proposed site (Exhs. ANP-JAG-1.10 C; ANP-JAG-8; Tr. 14, at 119-125). Mr. Brady therefore argued that the Company had underestimated the mix of residential land uses that exist in proximity to the proposed site, particularly with respect to areas in Franklin (JAG Brief at 5). The Company responded that it had accurately characterized the land uses within one mile of the proposed site and argued that Mr. Brady was unable to specify the location of the center-point used to define the area of Franklin that was the focus of his analysis (Company Brief at 180). The Company therefore asserted that the data introduced by Mr. Brady could not be verified, and hence was unreliable (id.).

The Company stated that the proposed site is located within the industrial zone, and that its proposed facility is a permitted use under this zoning category (Exh. BEL-1, at 6-64). The Company indicated that in order to comply with all Town of Bellingham zoning restrictions, it would secure special permits from the Zoning Board of Appeals ("ZBA") relative to four specific issues: (1) standard height restrictions, (2) air emissions, (3) on-site storage and use of hazardous materials and waste, and (4) use of temporary structures and authorization for parking of light and heavy commercial vehicles at the site during the construction period (Exhs. HO-EL-6.1, at Tab 2; HO-EL-9).[151] The Company indicated that effective February 5, 1998, it had received conditional approvals from the Bellingham ZBA with respect to each of the four special permit applications (Exh. HO-RR-30.1). The Company indicated that it had not yet filed its Site Plan with the Town of Bellingham Planning Board, but that it intended to do so in May of 1998 (Tr. 15, at 45).

With respect to impacts to wildlife species and habitats at the proposed site, the Company stated that, based on its initial consultation with the Massachusetts Natural Heritage and Endangered Species Program ("NHESP"), no species of special concern or significant habitats were identified in the vicinity of the proposed site (Exh. BEL-1, at 6-57). The Company also stated that there were no known rare plants, animals, or exemplary communities in the project area (id.). However, the Company noted that three wetland areas located within the site boundaries contained features that were consistent with "vernal pool habitat" as defined in the Wetlands Protection Act regulations (310 CMR 10.04), and stated that it subsequently identified and described those features in documentation submitted to NHESP and in its Wetland Notice of Intent (See Exh. BCC (2)-W-5.1) for the project (id.; Exh. BCC-W-11; Tr. 11, at 68-74). In addition, the Company stated that a spotted turtle, a "species of special concern" in Massachusetts, had been discovered during a survey of the proposed site (Exh. BEL-1, at 6-57).

The Company stated that none of the identified vernal pool habitats would be located within the project footprint area, and indicated that it had developed a set of mitigation measures specific to the presence of spotted turtles at the site including: (1) education of project personnel in the identification of the spotted turtle; (2) fencing and barriers to prevent movement of turtles into construction areas; (3) daily inspections for, and relocation of, turtles away from construction activity; and (4) restoration of disturbed areas following construction to establish conditions that would be adequate for turtle migration and nesting (Exh. BCC (2)-W-5.1, at 2-6 to 2-12, and 3-6; Tr. 12, at 72-74). The Company asserted that these measures would prevent adverse short-term and long-term impacts to the spotted turtle and its habitat during both construction and operation of the proposed facility (id.;

Tr. 15, at 104-107).[152]

The Company indicated that an initial survey for historic and archaeological resources found the proposed site to be of low to moderate sensitivity with respect to such resources (Exh. BEL-15, Vol. 1 at 13-4). The Company stated that the Public Archaeology Laboratory, Inc. ("PAL"), under the direction of the Massachusetts Historical Commission ("MHC"), performed a site examination to further characterize any historic or archaeological resources at the proposed site and concluded that the site did not meet eligibility criteria for listing in the National Register of Historic Places (id. at 13-1). MHC therefore determined that no additional archaeological investigation of the site is warranted (Exhs. HO-EL-13;

HO-EL-13.1; April 9 MHC letter to MEPA).

With respect to off-site impacts associated with construction of utility interconnects for the proposed project, the Company stated that the gas supply interconnect would consist of a 1.11 mile natural gas pipeline that would be constructed, owned and operated by AGT. The interconnect currently is the subject of a separate proceeding before the FERC (Docket CP98-100-000).[153] The Company indicated that the preferred route for the gas pipeline would require temporary and permanent clearing of both upland and wetland woods along a new easement (Tr. 15, at 58-63). The Company stated that a permanent easement covering 5.08 acres would be required for the pipeline, within which 3.36 acres of upland woods, and .02 acres of wetland woods, would be cleared and maintained free of woody vegetation[154] (id.

at 60). The Company asserted that the FERC review would ensure that the environmental impacts of the gas pipeline interconnect would be minimized consistent with FERC standards (Company Brief at 137). (See Section III.B.2.b.(1) above, for a discussion of wetland impacts related to the AGT pipeline).

Finally, the Company stated that water and sewer interconnects for the proposed facility would be co-located with the project access driveway, and that therefore, no incremental impacts would result from the construction of those facilities (id. at 59 to 60).

(2) 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 proposed site and surrounding areas on three sides are zoned for industrial use, and that abutting areas are a mixture of vacant, residential and commercial uses. The record further indicates that the area within one half mile of the proposed site is predominantly open land, with approximately 20 percent being used for residential or commercial purposes.

The proposed facility is an allowed use under the zoning by-laws of the Town of Bellingham. The Siting Board notes that the proposed stacks and other facility structures would be considerably taller than existing structures in the area, but that the project proponent has received conditional approval of its four Special Permit applications before the Bellingham ZBA to construct the facility with building heights and other characteristics as currently proposed.

The Company has adequately considered the impacts of the proposed facility with respect to wildlife species and habitats and historic and archaeological resources.[155] Moreover, the Siting Board notes that the proposed project will undergo additional reviews by other authorities with respect to these issues including a 401 Water Quality Certificate, and an Order of Conditions to be issued by the Bellingham Conservation Commission.

The Siting Board has considered the adequacy of site buffering and proposed mitigation to limit the visual and noise impacts of the proposed facility in Sections III.B.2.d and III.B.2.e, above. Further, the Siting Board has imposed conditions with respect to visual and noise impacts of the proposed facility in Sections III.B.2.d and III.B.2.e, above, and notes that these conditions address, to a significant degree, the issue of consistency with land use objectives.

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

3. Cost

In this section, the Siting Board evaluates whether the Company has provided sufficient information on the costs of the proposed facility to allow the Siting Board to determine if an appropriate balance has been achieved between environmental impacts and costs.

The Company stated that the total cost of the proposed facilities at the proposed site would be $300 million in 2000 dollars (Exh. HO-C-1; Tr. 11, at 4-5). The Company stated that this cost estimate reflects current site specific estimates of:
(1) construction costs; (2) electric transmission line and gas pipeline interconnect costs; (3) a contingency allowance[156]; (4) site acquisition costs; and (5) licensing and development costs (id.). The Company asserted that the cost estimate was realistic for a facility of this size and design based on the Company's knowledge of costs for similar projects (Company Brief at 196).

The Company also considered the relative costs of several options to minimize further certain environmental impacts associated with the proposed facility, including options to reduce facility water use through alternatives to steam augmentation, and options to increase noise mitigation. With respect to the proposed use of steam augmentation to provide 40 MW of peak capacity, the Company presented heat rate information indicating its proposed peaking operations would show a heat rate increase (efficiency loss) of 24 percent above that for baseload operation at the proposed facility, as compared to a relative heat rate for new stand-alone simple cycle peaking capacity of 44 to 64 percent above that for baseload operation at the proposed facility (Exh. HO-RR-72R). As further evidence of the economic merits of its proposed use of steam augmentation, the Company maintained such operation would require only minimal additional piping equipment, with essentially no added capital cost and no effect on baseload operating cost (Exh. HO-EW-8). With respect to alternatives, the Company maintained that: (1) an alternative peaking design to allow supplemental firing of the HRSG would require larger air-cooling condensers and redesign of the steam turbine, with loss of baseload operating efficiency; (2) an alternative peaking design to reduce the gas turbine air inlet temperature would require a chilling plant, with a loss of baseload operating efficiency due to increased pressure drop in the gas turbine air inlet; and (3) alternative stand-alone peaking capacity would involve substantial capital costs, as well as the less favorable heat rate during peaking operations, discussed above (Exh. HO-RR-65.1, at 3-36 to 3-37;

Tr. 11, at 103-104).

As noted above in Section III.B.2.d, the Company indicated that noise mitigation technology to further reduce the noise impacts at the most affected residential and property line noise receptors would cost: (1) an additional $3.0 million to limit the noise increase over the L_{90} to 7-8 dBA at residences, and (2) an additional $10.7 million to limit the noise increase over the L_{90} to 10 dBA at the most affected property line receptors (Exh. HO-RR-76 (Rev.)).

The record contains estimates of the overall costs of the proposed facility at the proposed site, as well as information on relative costs for measures to further minimize environmental impacts.

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 whether an appropriate balance would be achieved between environmental impacts and cost.

Based on our review of the entire record in this case, the Siting Board finds that the project proponent has provided sufficient information regarding environmental impacts and potential mitigation measures to allow us to determine if the appropriate balance among environmental impacts and between environmental impacts and cost has been achieved.

4. Conclusions on the Proposed Facility

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.

The Siting Board has found that, with the implementation of the conditions specified in Section III.B.2 above, the environmental impacts of the proposed facility at the primary site would be minimized with respect to air quality, water supply, water-related discharges, construction related impacts to wetlands, visual impacts, traffic, safety, EMF, and land use. Further, in Section III.B.3, the Siting Board has found that ANP has provided sufficient information on the costs of the proposed facility to allow the Siting Board to determine whether an appropriate balance would be achieved between environmental impacts and cost.

The record indicates that there are no significant issues involving the balance among water-related discharges, construction related impacts to wetlands, traffic, safety, EMF and land use, nor between any of these concerns and cost.

In Section III.B.2.b, above, the Siting Board examined the trade-offs between air quality, water supply, visual impacts and cost associated with the use of steam augmentation, and based on our analysis of the trade-offs and the proposed mitigation for water supply impacts, concluded that the water supply impacts of the proposed facility would be minimized with use of steam augmentation.

In Sections III.B.2.d, above, the Siting Board examined the trade-offs between noise and cost associated with identified noise mitigation options, and found that, with the implementation of proposed mitigation, the environmental impacts of the proposed facility with respect to noise would be minimized, consistent with minimizing cost.

In Section III.A, above, the Siting Board found that ANP has considered a reasonable range of practical facility siting alternatives.

Therefore, the Siting Board finds that, with the implementation of the conditions set forth in Sections III.B.2 above, (1) the proposed facility would be sited, designed and mitigated in a manner that minimizes environmental impacts and costs, and (2) an appropriate balance would be achieved among conflicting environmental concerns as well as between environmental impacts and cost.

IV. DECISION

The Siting Board's enabling statute directs the Siting Board to implement the energy policies contained in G.L. c. 164, §§ 69H-69Q to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. G.L. c. 164, § 69H. In addition, the statute requires the Siting Board to determine whether plans for expansion or construction of energy facilities are consistent with the current health, environmental protection, and resource use and development policies as adopted by the Commonwealth. G.L. c. 164, § 69J.

In Section II.A, above, the Siting Board has found that the Company has established need for the proposed project. Further, in Sections II.B and II.C, above, the Siting Board has found that the proposed project is superior to all alternative technologies reviewed with respect to providing a necessary energy supply with a minimum impact on the environment at the lowest possible cost, and that upon compliance with the listed conditions, ANP has established that its proposed project is reasonably likely to be a viable source of energy. In Section III.A, above, the Siting Board has found that ANP has considered a reasonable range of practical facility siting alternatives. In Section III.B, above, the Siting Board has found that with implementation of the listed conditions relative to air quality, water supply, visual impacts, noise, and traffic, the proposed facility would be sited, designed and mitigated in a manner that minimizes environmental impacts and costs, and an appropriate balance would be achieved among conflicting environmental concerns as well as among environmental impacts and cost.

Accordingly, the Siting Board finds that, upon compliance with the conditions set forth in Sections II.C, and III.B, above, and listed below, the construction and operation of the proposed facility will provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

In Sections III.A and III.B, above, the Siting Board has reviewed various environmental impacts of the proposed facility in light of related regulatory or other programs of the Commonwealth, including programs relating to air quality, water supply, water-related discharges, wetlands protection, noise, rare and endangered species, 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.

Accordingly, the Siting Board APPROVES the petition of ANP Bellingham Energy Company to construct a 580 MW bulk generating facility and ancillary facilities in Bellingham, Massachusetts subject to the following conditions during construction and operation of the proposed facility:

(A) In order to ensure that the project is likely to be constructed within the applicable time frames and be capable of meeting performance objectives, the Siting Board directs ANP to provide: (1) a copy of a signed EPC contract between ANP and ABB or a comparable entity that contains provisions that would provide reasonable assurance that the project would perform as a low-cost, clean power producer, and (2) a copy of a signed interconnection agreement between the Company and NEPCo providing the proposed project with access to the regional transmission system.

(B) In order to mitigate CO_2 emissions, the Siting Board requires ANP to provide CO_2 offsets through a total contribution of $620,690, to be paid in five annual installments during the first five years of facility operation, plus a contribution of $35,100 in the first year of facility operation as an offset for on-site tree clearing, to a cost-effective CO_2 offset program or programs to be selected upon consultation with Siting Board Staff. If the Company chooses to provide the entire donation within the first year of facility operation, the CO_2 offset requirement would be a total contribution in the amount of $503,040 to a cost-effective CO_2 offset program or programs to be selected upon consultation with Siting Board Staff.

(C) In order to minimize impacts to water resources, the Siting Board directs the Company to work with Charles River Watershed Association to ensure periodic documentation of program activities and results to the Company, and to share periodic reports with Town of Bellingham officials and the Siting Board.

(D) In order to minimize visual impacts, the Siting Board directs the Company, consistent with the directives in Section III.B.2.c, to provide reasonable off-site mitigation of visual impacts, including shrubs, trees, window awnings or other mutually-agreeable measures, that would screen views of the proposed facility at properties along Maple Street, and at other locations within one mile of the proposed facility, as requested by residents or appropriate municipal officials. In this regard, the Company: (1) shall provide shrub and tree plantings or window awnings on private property, only with the permission of the property owner, and along public ways, only with the permission of the appropriate municipal officials; (2) shall provide written notice of this requirement to public officials in Bellingham and Franklin and to all affected property owners prior to the commencement of construction; (3) may limit requests from local residents and town officials for mitigation measures to a specified period ending no less than six months after initial operation of the plant; (4) shall complete all such mitigation measures within one year after completion of construction, or if based on a request after commencement of construction, within one year after such request; and (5) shall be responsible for the reasonable maintenance or replacement plantings as necessary to ensure that healthy plantings become established.

(E) In order to alleviate public concern, the Siting Board requires the Company to provide a report to the Siting Board and the Town of Bellingham ZBA including: (a) a description of its noise testing protocol; (b) the results of its noise testing; (c) an assessment of any operating or maintenance factors, including weather conditions or equipment problems, that may have contributed to the result; (d) records of any complaints received concerning noise from the facility since start-up; and (e) any steps the Company plans to take, or has considered taking, to reduce plant noise. If noise testing indicates an actual L_{90} noise increase of greater than 8.0 dBA, the Company is further directed to assess options for such noise mitigation as would be required to bring the facility into compliance with the 8.0 dBA increase accepted by the Siting Board and the Town of Bellingham ZBA.

(F) In order to minimize traffic related impacts, the Siting Board requires the Company, in consultation with MHD and the Towns of Bellingham, Franklin, Wrentham and Foxborough, to develop and implement a traffic mitigation plan which addresses intersection control, scheduling, and roadway and bridge construction.[157] With respect to intersection control, the Company is directed to coordinate with the appropriate authorities to place officer controls at unsignalized gateway intersections, and at other areas of concern as necessary, during the construction period. With respect to scheduling, the Company is directed to schedule, to the maximum extent practicable, arrivals and departures of construction related traffic, including but not limited to construction labor, deliveries of materials, equipment, and plant components, in a manner so as to avoid daily peak travel periods in affected areas. Such plans also should include steps to minimize traffic impacts associated with any roadway or bridge modifications, or other improvements, that may be required to effect delivery of large plant components.

(G) In order to provide the Siting Board with final design information relating to minimization of EMF impacts, the Siting Board directs ANP to provide an update on the extent and design of required transmission upgrades, and the measures incorporated into the transmission upgrade designs to minimize magnetic field impacts, at such time as

ANP reaches final agreement with all transmission providers regarding transmission upgrades.

Because issues addressed in this decision relative to this facility are subject to change over time, construction of the proposed generating facility and ancillary facilities must be commenced within three years of the date of this decision.

In addition, the Siting Board notes that the findings in this decision are based upon the record in this case. A project proponent has an absolute obligation to construct and operate its facility in conformance with all aspects of its proposal as presented to the Siting Board. Therefore, the Siting Board requires the Company to notify the Siting Board of changes other

than minor variations to the proposal so that the Siting Board may decide whether to inquire further into a particular issue. The Company is obligated to provide the Siting Board with sufficient information on changes to the proposed project to enable the Siting Board to make these determinations.

M. Kathryn Sedor

Hearing Officer

Dated this 18th day of August 1998

TABLE A-1

PERMITTED WITHDRAWAL VOLUMES, ACTUAL AVERAGE DAILY WATER USE

AND TOTAL ANNUAL WATER USE BY BASIN, TOWN OF BELLINGHAM, 1993-1996

	Well #	Permitted Approved Daily Volume	1993 Total	1993 Daily Average	1994 Total	1994 Daily Average	1995 Total	1995 Daily Average
Blackstone River Basin	No. 1	0.52	93.2	0.26	97.52	0.27	97.3	0.27
	No. 2	0.36	9.8	0.03	0	0	0	0
	No. 3	0.65	65.9	0.18	57.16	0.16	40.46	0.11
	No. 4	0.52	145.3	0.40	105.33	0.29	158.92	0.44
	No. 11	0.36	92.1	0.25	91.35	0.25	95.44	0.26
Basin Subtotal:		2.41	406.30	1.11	351.36	0.96	392.12	1.07
Percent of System Total:		51%	68%	68%	54%	54%	61%	61%
Charles River Basin	No. 5	0.29	82.1	0.22	100.04	0.27	81.77	0.22
	No. 7	0.61	39.2	0.11	104.29	0.29	67.67	0.19
	No. 8	0.90	70.9	0.19	99.27	0.27	97.88	0.27
	No. 12	0.50	0	0	0	0	0	0
Basin Subtotal:		2.30	192.20	0.53	303.60	0.83	247.32	0.68
Percent of System Total:		49%	32%	32%	46%	46%	39%	39%

All values in millions of gallons

TABLE A-2

RELATIONSHIP BETWEEN RECHARGE AND WITHDRAWAL RATES,

BY AQUIFER, BELLINGHAM, MA, 1993-1996

Wells	Zone II Area (sq. mi.) A	Precipitation Recharge per Sq. Mi. (mgd) B	Total Recharge from Precipitation C (=A x B)	Ave. Aquifer Withdrawal 1983-1996 (mgd)
No. 5	0.52	1.0	0.52	0.23
No. 12	1.18	1.0	1.18	0
No. 7, 8	1.85	1.0	1.85	0.42
No. 1, 2, 3, 4, 11	3.68	1.0	3.68	1.04

TABLE A-3

SUBBASIN LOW-FLOW DATA AND

CONTRACTED SUMMER PROJECT WATER USE,

TOWN OF BELLINGHAM, STANDARD RATES

Subbasin	7Q10 Flow (mgd)	Average Summer Flow (July-Sept.) (mgd)	Summer H2O Use, ANP-Bellingham, Std. Rates
Charles - Millis	9.4	34.3	0.05
Blackstone - Woonsocket	65.3	212	0.05
Blackstone - Peters Brook[*]	0.45	No data	0.05

* Flows and project water use data for Peters Brook are subsumed in the data for Blackstone - Woonsocket.

APPROVED by the Energy Facilities Siting Board at its meeting of August 13, 1998, by the members and designees present and voting: Janet Gail Besser (Chair, EFSB/DTE); W. Robert Keating (Commissioner, DTE); James Connelly (Commissioner, DTE); Sonia Hamel (for Trudy Coxe, Secretary of Environmental Affairs); and David O'Connor (for David A. Tibbetts, Director of Economic Development).

Janet Gail Besser, Chair

Energy Facilities Siting Board

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).