COMMONWEALTH OF MASSACHUSETTS

Energy Facilities Siting Board

)

In the Matter of the Petition of)

U.S. Generating Company) EFSB 96-4

for Approval to Construct)

a Bulk Generation Facility and Ancillary Facilities)

in Charlton, Massachusetts)

)

FINAL DECISION

Jolette A. Westbrook

Hearing Officer

November 3, 1997

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FIGURES:

FIGURE 1: Primary Site Vicinity Map

FIGURE 2: Alternative Site Vicinity Map

LIST OF ABBREVIATIONS

Abbreviation Explanation

AALS Allowable Ambient Limits

ACOE Army Corps of Engineers

AFB Atmospheric fluidized bed

AO American Optical

BACT Best available control technology

BPC Bechtel Power Corporation

BPD Berkshire Power Development, Inc.

CAAA Federal Clean Air Act Amendments of 1990

CDM Camp, Dresser, McKee

CELT 1996 Capacity, Energy, Loads and Transmission Report published by NEPOOL

CGCC Coal gasification -- combined cycle

Charlton Town of Charlton

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

CO Carbon monoxide

CO2 Carbon dioxide

Company U.S. Generating Company

Court Massachusetts Supreme Judicial Court

CT Combustion turbine peaking unit

dBA A-weighted decibel

DCR Debt coverage ratios

DEIR Draft Environmental Impact Report

Department Department of Public Utilities

DFW Division of Fisheries and Wildlife

DO Dissolved oxygen

$/kWh Dollars per kilowatt-hour

DPA Dighton Power Associates Limited Partnership

DSM Demand Side Management

EIA Energy Information Administration

EMF Electric and magnetic fields

ENF Environmental Notification Form

EPA The United States Environmental Protection Agency

EPC contract Turnkey construction contract

EPRI Electric Power Research Institute

ERCs Emission reduction credits

ERG Economic Resource Group

FEIR Final Environmental Impact Report

FERC Federal Energy Regulatory Commission

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

GEP Good Engineering Practice

gpd gallons per day

GTCC Gas-fired combined cycle unit

GTCC alternative GTCC with oil backup used in the Company's alternative technology analysis

GTF Generation Task Force

HQ II Hydro-Quebec Phase II

HRSG Heat recovery steam generator

IDLH Immediately Dangerous to Life or Health

IGCC Integrated coal gasification combined cycle unit

IGCC alternative The IGCC used in the Company's alternative technology analysis

IPP Independent power producer

IWPA Interim Wellhead Protective Area

kV Kilovolt

KWh Killowatthours

L50 The level of noise that is exceeded 50 percent of the time

L90 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

Ldn 24-hour A-weighted equivalent sound level with a 10 decibel penalty applied to nighttime levels

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

MAAQS Massachusetts ambient air quality standards

Mcf/d Million cubic feet per day

MCZM Massachusetts Coastal Zone Management

MDEM Massachusetts Department of Environmental Management

MDEP Massachusetts Department of Environmental Protection

MECo Massachusetts Electric Company

mG Milligauss

mgd Million gallons per day

MHD Massachusetts Highway Department

Millennium Millennium Power Project

Millennium-in case A detailed economic analysis based on NEPOOL dispatch practices for the period 2000 through 2005, which include a dispatch analysis of the proposed facility

Millennium-out case A detailed economic analysis based on NEPOOL dispatch practices for the period 2000 through 2005, which did not include the dispatch of the proposed facility

Mitsubishi Mitsubishi Heavy Industries

MMWEC Massachusetts Municipal Wholesale Electric Company

MPP Millennium Power Project

MPPLP Millennium Power Partners, L.P.

MVA Megavoltamperes

MW Megawatt

NAAQS National ambient air quality standards

NEC Nantucket Electric Company

NEES New England Electric System

NEPCo New England Power Company

NEPOOL New England Power Pool

1996 CELT forecast Regional load forecast derived from NEPOOL's 1996 CELT report reference forecasts of unadjusted summer and winter peak loads

1997 CELT forecast Regional load forecast derived from NEPOOL's 1997 CELT report reference forecasts of unadjusted summer and winter peak loads

NEPSCo New England Power Services Company

New Hampshire PUC New Hampshire Public Utilities Commission

NHESP Natural Heritage and Endangered Species Program

NOx Nitrogen oxides

NPDES National Pollutant Discharge Elimination System

NPV Net present value

NRC Nuclear Regulatory Commission

NSPS New Source Performance Standards

NSR New Source Review

NU Northeast Utilities

NUG Non-utility generator

O3 Ground-level ozone

O&M Operation and maintenance

Pb Lead

PC Pulverized coal facility

PFBC Pressurized fluidized bed coal facility

PG&E PG&E Enterprises

PM-10 Particulates

PPA Power purchase agreement

PPM Parts per million

PSD Prevention of significant deterioration

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

QF Qualifying facility

ROW Right-of-way

SACTI Seasonal/Annual Cooling Tower Plume Impact model

SCR Selective Catalytic Reduction

SEC Securities Exchange Commission

SILs Significant impact levels

Siting Board Energy Facilities Siting Board

Siting Council Energy Facilities Siting Council

Southbridge Town of Southbridge

SO2 Sulfur dioxide

SOx Sulfur oxides

TAG EPRI Technical Assessment Guide

TDS Total Dissolved Solids

TEC Taunton Energy Center

TELs Threshold Effect Exposure Lines

TGP Tennessee Gas Pipeline Company

Town Town of Charlton

tpy Tons per year

USGen U.S. Generating Company

USGenFS USGen Fuel Services

USGenPS USGen Power Services, Inc.

USOSC U.S. Operating Service Company

VOCs Volatile organic compounds

Westinghouse 501G Combustion turbine to be used at proposed facility

WMA Massachusetts Water Management Act

WWTP Wastewater Treatment Plant

ZBA Zoning Board of Appeals

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

I. INTRODUCTION

A. Summary of the Proposed Project and Facilities

U. S. Generating Company ("USGen" or "Company") has proposed to construct a nominal net 360-megawatt ("MW") natural gas-fired, combined-cycle electric power plant (the "Millennium project" or "proposed project") on approximately 15-acres of a

120-acre site located in the Town of Charlton, Massachusetts ("Town" or "Charlton"). The proposed facility would commence commercial operation in the year 2000 (Exhs. MPP-0, at 1-2; MPP-11, at 6).

The proposed facility would be powered with natural gas delivered through a

high-pressure pipeline interconnection with the nearby Tennessee Gas Pipeline Company ("TGP") facility, using low-sulfur (0.05 percent) distillate oil as a back-up fuel

(Exhs. MPP-0, at 1-6; MPP-7, at 3, 6). The proposed facility would have an on-site fuel oil storage tank capable of holding enough oil to fuel the proposed facility for three consecutive days (Exhs. MPP-7, at 6; EFSB V-18a).

The major components of the proposed project include: (1) a Westinghouse 501G combustion turbine, which will generate approximately 240 MW of electricity; (2) a heat recovery steam generator ("HRSG"); (3) a steam turbine and generator which will produce an additional 120 MW of electricity; (4) a selective catalytic reduction system for control of nitrogen oxides ("NOx"); (5) a conventional induced mechanical draft wet cooling tower; and (6) a 225-foot exhaust stack (Exhs. MPP-0, at 1-6; MPP-11, at 3; MPP-11, att. 1;

EFSB E-47 (rev. A)). Additional components include a 1.2-million gallon fuel oil storage tank, an ammonia storage tank, water tanks and electrical and water treatment equipment (Exhs. MPP-0, at 1-6; EFSB E-122 (rev. A)).

The Company's proposed site is located in an area of Charlton zoned

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

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

The proposed project is being developed by USGen (Exh. MPP-0, at 1-1). USGen is owned by PG&E Enterprises ("PG&E") and is an affiliate of Millennium Power Partners, L.P. ("MPPLP") (Exhs. MPP-0, at 1-1; EFSB V-2a (rev. A)). MPPLP, which will be the owner of the proposed project, is a Delaware limited partnership qualified to do business in Massachusetts (Exh. EFSB V-2a (rev. A)). USGen and its affiliates have ownership

and/or management responsibilities in 17 electric power plants, one natural gas storage project, and two interstate natural gas pipeline projects (id.).

B. Jurisdiction

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

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

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

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

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

C. Procedural History

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

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

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

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

In March 1997, the Siting Board received late-filed petitions to intervene from: William C. Sullivan, Sr. ("Mr. Sullivan"); James and Tracy Sullivan (the "Sullivans"); David E. Matte ("Mr. Matte"); Ian MacFarlane ("Mr. MacFarlane"); Dennis P. and Barbara Grenke (the "Grenkes"); James and Deborah Evans (the "Evanses"); Kenneth and Martha Bergstrom (the "Bergstroms"); and Florence M. Scanlon ("Ms. Scanlon"). In April 1997, the Siting Board received late-filed petitions from: Jane Shropshire ("Ms. Shropshire"); Steven Gardner ("Mr. Gardner"); Stephen E. Milosh ("Mr. Milosh"); and Gina M. DiPietro ("Ms. DiPietro").(6) In June 1997, the Siting Board received a late-filed petition to intervene from Tammra Russell ("Ms. Russell"), filing in her capacity as Selectman for the Town.(7)

The Hearing Officer denied the late-filed petitions to intervene of Mr. Sullivan, the Sullivans, Mr. Matte, Mr. MacFarlane, the Grenkes, the Evanses, the Bergstroms,

Ms. Scanlon, Ms. Shropshire, Mr. Gardner, Mr. Milosh, Ms. DiPietro and Ms. Russell (Hearing Officer Procedural Orders, March 28, 1997, at 5; April 9, 1997, at 4; April 18, 1997; July 24, 1997). On April 3, 1997, Mr. Matte filed a request for reconsideration which the Hearing Officer also denied (Hearing Officer Procedural Order, April 18, 1997, at 4).

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

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

The Siting Board conducted ten days of evidentiary hearings commencing on

May 28, 1997 and ending on June 20, 1997. The Company presented the testimony of twelve witnesses: Dr. Susan F. Tierney, principal with the Economics Resource Group ("ERG"), who testified as to the need for the proposed project; Gary A. Lambert, Jr., director of development, northeast region, for the Company, who testified as to viability, site selection, water, alternative technology, air, visual, carbon dioxide ("CO2"), cost and other issues; Douglas F. Egan, senior vice president, northeast region, for the Company, who testified as to viability and site selection; William B. Daniels, director of finance for the Company, who testified as to viability; Patrick J. West, project engineer for the Company, who testified as to noise, water, air, visual, CO2, traffic and safety issues, and construction cost and alternative technologies; Mark D. Winne, director, combined-cycle maintenance for the Company, who testified as to operation, maintenance and safety; Norman D. Karloff, manager of fuel procurement for the Company, who testified as to the project's fuel acquisition strategy; Michael D. Petit, director, project management services for the Company, who testified as to fuel supply; Frederick M. Sellars, vice president of Earth Tech, who testified as to site selection, noise, water, alternative technology, air, visual, CO2, traffic, safety, land use and cost issues; Dr. William H. Bailey, president of Bailey Research Associates, Inc., who testified as to electric and magnetic field issues ("EMF");

George F. Hessler, Jr., P.E., an acoustical engineer with Hessler Associates, Inc., who testified as to noise impact and noise mitigation issues; and Kathleen D. Hathaway, manager of project development for the Company, who testified as to site selection.

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

D. Scope of Review

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

approaches in the ability to address the previously identified need and in terms of cost, environmental impact, and reliability. Dighton Power Decision, EFSB 96-3, at 5; Berkshire Power Decision, 4 DOMSB at 243; NEA Decision, 16 DOMSC at 364 (see Section II.B, below). Third, the Siting Board requires the applicant to show that its project is viable. Dighton Power Decision, EFSB 96-3, at 6; Berkshire Power Decision, 4 DOMSB at 243; NEA Decision, 16 DOMSC at 364 (see Section II.C, below). Fourth, the Siting Board requires the applicant to show that its site selection process did not overlook or eliminate clearly superior sites, and in cases where an alternative site has been noticed, that the proposed site for the facility is superior to the alternative site in terms of cost, environmental impact, and reliability of supply. Dighton Power Decision, EFSB 96-3, at 6; Berkshire Power Decision, 4 DOMSB at 243; NEA Decision, 16 DOMSC at 343 (see Section III.A, below). Finally, the Siting Board requires that a proposed project minimize environmental impacts and achieve an appropriate balance among conflicting environmental concerns as well as among environmental impacts, cost and reliability of supply at the site which is approved. Dighton Power Decision, EFSB 96-3, at 6; Berkshire Power Decision 4 DOMSB at 243; Boston Edison Company, 1 DOMSB 1, 149-153, 186-195 (1993) ("1993 BECo Decision") (see Section III.B below).

II. ANALYSIS OF THE PROPOSED PROJECT

A. Need Analysis

1. Standard of Review

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

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

necessary energy supply for the commonwealth (emphasis added)." 413 Mass. at 490, citing G.L.

c. 164, § 69H.

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

With respect to the issue of regional need versus Massachusetts need, the Siting Board noted the integration of the Massachusetts electricity system with the regional electricity system and the resulting link between Massachusetts and regional reliability (id. at 422). The Siting Board noted the inherent reliability and economic benefits which flow to Massachusetts as a result of this integration (id.). Thus, the Siting Board concluded that consideration of regional need must be a central part of any need analysis for a power generation project not linked to individual utilities by power purchase agreements ("PPAs") (id. at 416). The Siting Board also noted that the Massachusetts Legislature clearly foresaw the need for "cooperation and joint participation in developing and implementing a regional bulk power supply of electricity" when it enacted G.L. c. 164A and in this same enactment acknowledged that power generating facilities would provide electric power across state lines. G.L. c. 164A, §§ 3, 4. Accordingly, the Siting Board found that an analysis of regional need must serve as a foundation for an analysis of Massachusetts need. EEC (remand) Decision, 1 DOMSB at 417.

In evaluating the need for new energy resources to meet reliability objectives, the Siting Board may evaluate the reliability of supply systems in the event of changes in demand or supply, or in the event of certain contingencies. With respect to changes in demand or supply, the Siting Board has found that new capacity is needed where projected future capacity available to a system is found to be inadequate to satisfy projected load and reserve requirements. Dighton Power Decision, EFSB 96-3, at 8; Berkshire Power Decision,

4 DOMSB at 245; New England Electric System, 2 DOMSC 1, 9 (1977). With regard to contingencies, the Siting Board has found that new capacity is needed in order to ensure that service to firm customers can be maintained in the event that a reasonably likely contingency occurs. Dighton Power Decision, EFSB 96-3, at 8; Berkshire Power Decision, 4 DOMSB at 245; Eastern Utilities Associates, 1 DOMSC 312, 316-318 (1977). The Siting Board also may determine under specific circumstances that additional energy resources are needed primarily for economic or environmental purposes related to the Commonwealth's energy supply. Dighton Power Decision, EFSB 96-3, at 9; Berkshire Power Decision,

4 DOMSB at 245; EEC (remand) Decision, 1 DOMSB at 422. With respect to the issue of establishing need on economic efficiency or environmental grounds, the Siting Board notes that such analyses of need would be consistent with its statutory obligation to ensure a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. G.L. c. 164, §§ 69H, 69J. Dighton Power Decision,

EFSB 96-3, at 8-9; Berkshire Power Decision, 4 DOMSB at 245-246; Enron Power Enterprise Corporation, 23 DOMSC 1, 49-62 (1991) ("Enron Decision").

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

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

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

2 DOMSB at 26.

In its first review of a petition by a non-utility generator ("NUG") to construct a jurisdictional facility, the Siting Board found that, consistent with current energy policies of the Commonwealth, Massachusetts benefits economically from the addition of cost-effective qualifying facility ("QF")(9) resources to its utilities' supply mix. NEA

Decision, 16 DOMSC at 358. In that case, the Siting Board also found (1) that a signed and approved PPA between a QF and a utility constitutes prima facie evidence of the utility's need for additional energy resources for economic efficiency purposes, and (2) that a signed and approved PPA which includes a capacity payment constitutes prima facie evidence for the need for additional energy resources for reliability purposes (id.). Thus, in cases where a non-utility developer sought to construct a jurisdictional generating facility principally for a specific utility purchaser or purchasers, the Siting Board has required the applicant to demonstrate that the utility or utilities need the facility to address reliability concerns or economic efficiency goals through presentation of signed and approved PPAs. MASSPOWER, Inc.,

21 DOMSC 196, 200 (1990); MASSPOWER, Inc., 20 DOMSC 1, 19-23, 32 (1990) ("MASSPOWER Decision"); Altresco-Pittsfield Decision, 17 DOMSC at 366-367. Two 1995 decisions of the Court, however, bring into question further reliance on such prima facie evidence in this and future cases.(10)

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

2. Reliability Need

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

to explicitly consider need for the proposed facility during the 1999/2000 to 2003 time period.

a. New England

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

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

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

i. Demand Forecasts

(A) Description

USGen presented forecasts of unadjusted summer and winter peak load and DSM savings derived from information contained in the 1996 Capacity, Energy, Loads and Transmission ("CELT") report published by NEPOOL (id.).(11) To develop forecasts of adjusted load, the Company combined each of these peak load forecasts with (1) the 1996 CELT report forecast of NUG netted from load, and (2) one of three forecasts of DSM savings based on the 1996 CELT report forecast of DSM savings (id.).

(1) Demand Forecast Methods

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

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

(2) DSM

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

(3) Adjusted Load Forecasts

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

(B) Analysis

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

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

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

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

Overall, the Company has presented one base case forecast adjusted by three forecasts of DSM. Given uncertainties in forecasting demand, the Siting Board has previously found that it is reasonable to include a range of forecasts in a company's reliability need analysis. See, e.g., Berkshire Power Decision, 4 DOMSB at 261, n.23. However, as noted

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

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

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

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

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

ii. Supply Forecasts

(A) Description

(1) Capacity Assumptions

USGen presented three supply scenarios based on the capacity projections in the 1996 CELT report -- a base supply scenario, a high supply scenario, and a low supply scenario (Exhs. MPP-0, at 2-9 to 2-15; MPP-13, at 3-6, exhs. 2.1-5 (rev. A), 2.1-6 (rev. A). The Company indicated that the base supply scenario reflects the resources included in the 1996 CELT report,(16) updated to incorporate current information (Exhs. MPP-0, at 2-10; MPP-13, at 4-6).

The Company stated that it made reductions to the 1996 NEPOOL supply projections to reflect actual changes to the NEPOOL supply including: (1) the removal of the proposed Taunton Energy Center ("TEC") as a committed resource (150 MW summer and winter);(17) (2) the retirement of the Connecticut Yankee unit (560 MW summer, 583 MW winter);(18) (3) the deactivation of the Millstone 1, 2 and 3 units through the summer of 1997 (2,632 MW summer, 2,669 MW winter); and (4) the derating of the Maine Yankee unit by ten percent (87 MW summer, 88 MW winter)(19) (Exhs. MPP-0, at 2-10 to 2-12; MPP-13, at 5 to 6, exhs. 2.1-5 (rev. A), 2.1-6 (rev. A)). The Company stated that it also made additions to the 1996 NEPOOL supply projections to reflect Northeast Utilities ("NU") temporary replacement capacity for the Millstone units for the summer of 1997 (417 MW) (Exh. MPP-13, exhs. 2.1-5 (rev. A), 2.1-6 (rev. A); Tr. 1 at 45-51).(20) In addition, consistent with NEPOOL assumptions, the Company stated that it assumed that the Hydro-Quebec Phase II ("HQ II") contract, which expires in June 2001, would not be renewed but that the HQ II transmission line would continue to provide reliability benefits with a capacity value of 85 percent of its current capacity (Exh. MPP-0, at 2-10).

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

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

The Company stated that the low supply scenario was based on the 1996 CELT report forecasted inventory of available capacity, adjusted for a reasonable set of contingencies that reduce the amount of available generation capacity (id.). For the low supply scenario, the Company assumed reductions to the base supply scenario to reflect: (1) the retirement of 50 percent of all coal-fired and oil-fired capacity included in the 1996 CELT report but operating beyond NEPOOL retirement guidelines beginning in the winter of 1999/2000 (723 MW in summer 2000 increasing to 2,808 MW in summer 2009, 729 MW in winter 1999/2000 increasing to 2,839 MW in winter 2008/2009);(25) (2) the retirement of the Millstone 1 unit (641 MW summer, 648 MW winter);(26) (3) the reduction in the capacity value of the HQ II transmission line to 50 percent of its present value beginning in 2001 (520 MW summer, 167 MW winter); and (4) the cancellation of the BPD project (Exhs. MPP-0, at 2-12 to 2-14; MPP-13, at 5, exh. 2.1-6 (rev. A)). In addition, the Company added capacity to reflect continued operation beyond the summer of 1997 of the units put into service in Connecticut in 1996 under emergency approvals due to the outage of the Millstone units (417 MW beginning in summer 1997, dropping to 160 MW in summer 2002, 330 MW in winter 1997/98, dropping to 160 MW in winter 2001/02) (Tr. 1, at 47-51).(27)

The Company stated that the high supply scenario also was based on the 1996 CELT forecasted inventory of available capacity but adjusted for a set of assumptions that increase the amount of available generation over the forecast period (id.). For the high supply scenario, the Company added capacity to the base supply scenario including: (1) 50 percent of planned utility capacity additions classified as under licensing consideration in the 1996 CELT report (3 MW summer and winter); (2) 25 percent of the planned utility capacity additions classified as proposed in the 1995 CELT report (62 MW in summer 2000, increasing to 95 MW in summer 2005, 62 MW in winter 1999/2000, increasing to 100 MW winter 2004/05); and (3) the capacity of the DPA project (170 MW summer and winter)(28) (Exhs. MPP-0, at 2-15; MPP-13, exhs. 2.1-5 (rev. A) 2.1-6 (rev. A). In addition, the Company assumed that: (1) there would be reduction in the capacity value of the HQ transmission line (beginning in 2001, an additional 230 MW summer, 95 MW winter); (2) the Salem Harbor 3 unit would not be retired (an additional 143 MW summer and winter); (3) the Maine Yankee unit would not be derated (an additional 87 MW summer and winter); and (4) a smaller amount of emergency generating capacity put in service due to the outage of the Millstone units would remain in service (a reduction of 85 MW for summer 1998 to 2001, a reduction of 88 MW, for winter 1997/98 to 2000/01) (see n.20, above) (Exhs. MPP-0, at 2-15; MPP-13, exhs. 2.1-5 (rev. A) 2.1-6 (rev. A)).

(2) Reserve Margin

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

(B) Analysis

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

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

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

accepts the Company's assumption that the Maine Yankee unit will be derated by ten percent over the forecast period. See n.19, above. See, Berkshire Power Decision, 4 DOMSC at 271.

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

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

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

iii. Need Forecasts

(A) Description

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

developed nine winter need forecasts in a similar manner (Exh. MPP-0, at 2-15 to 2-16.) Of these nine winter need forecasts, all demonstrate a sustained need for at least 360 MW of capacity beginning in 2000 (Exh. MPP-13, exh. 2.1-8 (rev. A)).(31) See Table 1, below.

Table 1

RANGE OF REGIONAL NEED CASES

Summer-2000 Demand Case	DSM High Supply	Base Supply	Low Supply
1996 CELT High	(1,021)	(1,408)	(2,360)
1996 CELT Base	(1,064)	(1,450)	(2,906)
1996 CELT Low	(1,105)	(1,492)	(2,948)

Winter - 1999/2000 Demand Case	DSM High Supply	Base Supply	Low Supply
1996 CELT High	(577)	(979)	(2,864)
1996 CELT Base	(619)	(1,021)	(2,402)
1996 CELT Low	(661)	(1,063)	(2,444)

Source: Exhs. MPP-13, exh. 2.1-8 (att.).

Note: Capacity deficits are shown in ().

(B) Analysis

In considering the Company's forecasts of summer and winter peak load, the Siting Board has found that the 1996 CELT forecast is an appropriate base case summer peak load and

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

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

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

b. Massachusetts

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

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

i. Demand Forecasts

(A) Description

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

(1) Demand Forecast Methods

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

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

In addition, to verify the robustness of its need analysis over extreme variations in demand, the Company presented a high and low forecast of summer and winter peak load demand in Massachusetts, based on prorating NEPOOL's high and low demand forecasts for New England by the method described above (id.; Exh. MPP-13, exh. 2.2-9 (rev. A)); Tr. 1, at 29).

(2) DSM

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

(3) Adjusted Load Forecasts

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

(B) Analysis

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

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

With respect to DSM, the Company provided three forecasts of DSM savings corresponding to the forecasts of DSM savings presented in its regional need analysis. The Siting Board reviewed the regional DSM forecasts in Section II.A.2.a.i, above. Consistent with its findings concerning the regional forecasts of DSM savings, the Siting

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

ii. Supply Forecasts

(A) Description

(1) Capacity Assumptions

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

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

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

(2) Reserve Margins

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

(B) Analysis

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

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

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

iii. Need Forecasts

(A) Description

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

Table 2

RANGE OF MASS NEED CASES

Summer-2000

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

Winter-1999/2000 Demand Case	DSM High Supply	Base Supply	Low Supply
1996 CELT High	51	(161)	(871)
1996 CELT Base	36	(176)	(887)
1996 CELT Low	20	(192)	(902)

Winter-2000/2001

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

Source: Exh. MPP-13, exh. 2.2-8 (att.).

Note: Capacity deficits are shown in ().

(B) Analysis

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

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

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

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

3. Economic Need

a. New England

i. Description

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

In support of its assertions with respect to the existing NEPOOL dispatch system, the Company provided a series of detailed economic analyses based on modeling of existing NEPOOL dispatch practices for the 6-year period, 2000 through 2005,(41) which compared the total incremental costs of two scenarios -- one that included the dispatch of the proposed facility ("Millennium-in case") and another that lacked the proposed facility in the dispatch ("Millennium-out case") (Exhs. MPP-0, at 2-24; MPP-13, exhs. 2.3-4 (rev. A), 2.3-5 (rev. A), 2.3-7 (rev. A); EFSB RR-5). The Company stated that these analyses demonstrate that the proposed facility would provide significant economic efficiency benefits to the region that would be equal to the difference of the region's cost of electricity under these two scenarios (Exh. MPP-0, at 2-24, 2-27). The Company stated that such economic efficiency benefits would accrue to the region either by (1) the displacement by the proposed project of more expensive power sources in NEPOOL's dispatch order, or (2) the offering of a lower-cost alternative for incremental construction (id. at 2-23).

The Company stated that it used the POWRSYM3 model to simulate NEPOOL's dispatch on an hourly basis over the forecast period (id. at 2-24).(42) The Company stated that inputs into the model included: (1) generation supply identical to the base case supply scenario; (2) load growth identical to the summer base peak load forecast; (3) the actual 1994 load duration curve;(43) (4) operating and cost characteristics of individual generating facilities;(44) (5) classification of specific units as must-run;(45) (6) addition of new generic capacity to meet projected regional capacity requirements;(46) (7) fuel price forecasts; and (8) operating characteristics and dispatch price for the proposed facility (id. at 2-23 to 2-26). For the generic units, the Company assumed that 80 MW combustion turbine peaking units ("CT") would meet the forecasted need prior to the year 2000 and that 225 MW, advanced technology, gas-fired, combined cycle units ("GTCC") would meet the need for each of the years after 2000 (id. at 2-26; Exhs. MPP-13, exh. 2.3-2 (rev. A); EFSB N-10). USGen stated that operating characteristics and costs of the generic units were derived from NEPOOL long-range planning assumptions presented in the 1996 NEPOOL GTF Report (Exhs. MPP-0, at 2-26, and exh. 2.3-1; EFSB N-12). The Company assumed that the generic GTCC units would be less efficient than the proposed project over the forecast period (Exh. EFSB N-10; Tr. 1, at 60-61).(47)

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

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

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

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

ii. Analysis

In the past, the Siting Board has determined that, in some instances, utilities need to add energy resources primarily for economic efficiency purposes. Specifically, in the 1985 MECo/NEPCo Decision, 13 DOMSC at 178-179, 183, 187, 246-247, and in Boston Gas Company, 11 DOMSC 159, 166-168 (1984), the Siting Board recognized the benefit of adding economic supplies to a specific utility system. In addition, where a non-utility developer has proposed a generating facility for a number of power purchasers that are as yet unknown, or for purchasers with retail service territories outside of Massachusetts, the Siting Board standard indicates that need may be established on either reliability, economic, or environmental grounds. Berkshire Power Decision, 4 DOMSB at 292-93; Cabot Decision, 2 DOMSB at 296-300; NEA Decision, 16 DOMSC at 344-360.

In previous reviews of non-utility proposals to construct electric generation projects, project proponents have argued that additional energy resources were needed in the region based on economic efficiency grounds, i.e., that the construction and operation of a particular project would result in a significant reduction in total cost of generating power in the New England region through the displacement of more expensive sources of

power. Berkshire Power Decision, 4 DOMSB at 285-292; Cabot Decision, 2 DOMSB at 292-296; MASSPOWER Decision, 20 DOMSC at 19.

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

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

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

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

As discussed above, the Siting Board is concerned that the Company may have overstated savings by assuming efficiency advantages relative to generic GTCC units placed in service later in the period of the analysis. However, we also recognize that efficiency

advantages assumed relative to generic units placed in service during the first two years of the analysis would continue to produce significant dispatch-based savings over the remainder of the six-year period in the Company's analysis, as well as beyond that period. Thus, the Company has established that New England would recognize economic savings of substantial magnitude from the operation of the proposed project during its first two years of operation, and continued savings of significant but less certain amounts over the first six years of operation, under a range of fuel price forecasts.

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

b. Massachusetts

i. Description

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

ii. Analysis

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

Here, in Section II.A.3.a.ii, above, the Siting Board found that there would be a need in New England for 360 MW of additional energy resources from the proposed project for

economic efficiency purposes beginning in 2000. In addition, the Company provided analyses that demonstrated the extent of savings that would accrue to Massachusetts -- savings due to the operation of the proposed facility that would range from $82.38 million to $83.85 million, discounted to year 1996 dollars, over the 2000 to 2005 time period.

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

4. Environmental Need

a. New England

i. Description

The Company asserted that the operation of the proposed facility would provide the region with substantial net benefits in the form of reduced system-wide emissions of pollutants, due to the displacement of less efficient, more polluting generation by the proposed facility (Exh. MPP-0, at 2-30). To demonstrate environmental benefits realized from the displacement of existing sources of air pollution, the Company presented a dispatch analysis comparing total system-wide emissions of sulfur dioxide ("SO2"); (2) NOx; and (3) carbon dioxide ("CO2") under two scenarios -- the Millennium-in case and the Millennium-out case (Exhs. MPP-13, exhs. 2.4-2 (rev. A), 2.4-3 (rev. A), 2.4-4 (rev. A); MPP-39).(51)

The Company indicated that it used the POWRSYM3 model and plant-specific emissions data(52) to determine regional emissions for each pollutant in tons per year ("tpy") (Exh. MPP-0, at 2-28). The emissions analysis assumes constant generic unit characteristics, emission rates, and oil/gas mix for dual fuel units over the six-year forecast period (id. at 2-25 to 2-26, 2-28 to 2-29; Exh. EFSB N-10; Tr. 1, at 60-61). However, to prevent an overestimation of the benefits of the proposed facility, the Company stated that it incorporated recent and anticipated environmental regulations into its analysis (Exh. MPP-0, at 2-29 to 2-30). Specifically, the Company stated that it: (1) based NOx emissions on plant compliance with recent NOx control requirements; (2) assumed existing plants would be required to meet CAAA requirements for SO2 that will be effective in 2000; and (3) included the cost of SO2 allowances for the proposed project and generic units (id., at 2-29 to 2-30; Exh. EFSB RR-4).(53)

The Company's analysis indicated that emissions of SO2, NOx and CO2 would be reduced in the Millennium-in case, compared to the Millennium-out case, over the 6-year period from 2000 through 2005 (Exh. MPP-13, exhs. 2.4-2 (rev. A), 2.4-3 (rev. A), 2.4-4 (rev. A)). Specifically, the Company's analysis indicated reductions over the six years of:

(1) 8,200 tons of SO2, or 0.71 percent of regional emissions; (2) 3,606 tons of NOx, or 0.82 percent of regional emissions; and (3) 3.30 million tons of CO2, or 1.27 percent of regional emissions (id.).(54)

In response to requests from the Siting Board staff, the Company also compared the emission reductions attributable to the Millennium project, as developed in its displacement analysis, to the emissions impacts of the proposed facility, as identified in its air quality analysis and included as an input to the Millennium-in case in the displacement analysis (Tr. 1, at 89-93). The Company indicated that the six-year emissions reductions for SO2, 8,200 tons, actually would be more than ten times larger than the proposed facility's SO2 emissions of 638.4 tons over the same period (Exhs. MPP-14, att. 1; MPP-13, exh. 2.4-2 (rev. A)). Similarly, the six-year emissions reductions for NOx, 3,606 tons, would be several times larger than the proposed facility's NOx emissions of 978 tons over the same period (Exhs. MPP-14, att. 1; MPP-13, exh. 2.4-3 (rev. A)).

With respect to CO2, the Company's analyses show that six-year emissions reductions, 3.30 million tons, would be 45 percent of the proposed facility's CO2 emissions of 7.41 million tons over the same period (Exhs. EFSB E-39; MPP-13, exh. 2.4-4 (rev. A)). The Company's witness, Dr. Tierney, maintained that the comparison did not detract from the Company's analysis indicating that the proposed project would provide CO2 benefits that help demonstrate a need for the project (Tr. 1, at 91-95). Dr. Tierney explained that the Millennium-in case includes the proposed facility's CO2 emissions, and at the same time results in lower regional CO2 emissions than the Millennium-out case (id.).

ii. Analysis

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

In the Enron Decision, the Siting Board found for the first time that a proposed generating project would provide Massachusetts with environmental benefits related to net changes in air emissions from existing and future generating facilities in Massachusetts. 23 DOMSC at 69-73. In more recent decisions, the Siting Board has found that applicants' projects likely would provide short-term air quality benefits for Massachusetts based on the initial displacement of existing generation and associated emissions. Cabot Decision, 2 DOMSC at 329; Altresco Lynn Decision, 2 DOMSB at 100; EEC (remand) Decision, 1 DOMSB at 325-335. However, the Siting Board identified shortcomings with those applicants' dispatch analyses for addressing the potential for long-term air quality benefits including: (1) the assumption that displaced

generation would be increasingly dispatched over time with continued load growth; (2) the assumption of constant emission rates over time, in pounds per million Btu ("lbs/MMBtu"), for generating units in the analysis; and (3) the failure to address the potential for significant amounts of retirement of existing generating units. Cabot Decision, 2 DOMSC at 328; Altresco Lynn Decision, 2 DOMSB at 100; EEC (remand) Decision, 1 DOMSB at 332-333. In a more recent review of a GTCC facility, the Siting Board raised concerns regarding assumed characteristics of future generic GTCC units in the dispatch analysis, including assumed efficiency and size relative to the proposed project.(55) Berkshire Power Decision, 4 DOMSB at 302.

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

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

The Company's analytical methods are similar to those used in past Siting Board reviews of generating facilities, although the time frame and some other elements of the analysis are different. Responding to concerns in past Siting Board reviews, the Company has focused its displacement analysis on the short run and taken into account reductions in allowable SO2 and NOx emissions rates that are likely to become effective before or during the period of analysis. However, other shortcomings identified in past Siting Board reviews, as highlighted above, continue to be a factor in the Company's displacement analysis.

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

Second, the Company's methods leave its displacement analysis open to concerns the Siting Board has identified in past reviews with respect to (1) assumed redispatch of

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

At the same time, the Siting Board notes that the Company was able to demonstrate, through its displacement analysis, reductions in six-year regional SO2 and NOx emissions that significantly exceed the proposed facility's SO2 and NOx emissions over the same period. Although we are concerned, as discussed above, that the Company may have overstated pollutant reductions by assuming efficiency advantages relative to generic GTCC units placed in service later in the period of analysis, we recognize that the analysis shows year-by-year reductions that are larger than the proposed facility's own emissions in each of the first two years of the analysis, as well as cumulatively over all six years.

The Company's displacement analysis shows regional CO2 emissions reductions which are nearly half of the proposed facility's CO2 emissions. As in the case of SO2 and NOx, we are concerned that the modeled reductions of CO2 for later years of the analysis may have been overstated by assuming an efficiency advantage for the proposed project relative to generic GTCC units, but also recognize that year-by-year reductions are shown for each of the earlier years of the analysis. We further note, however, that the modeled CO2 emissions reductions demonstrate displacement benefits that only partially offset the proposed facility's CO2 emissions. The analysis does not include scenarios incorporating significant amounts of retirement of fossil fuel generation, relative to the extent of fossil fuel capacity expansion, or other offsetting factor that would demonstrate significant progress in meeting environmental goals.(56)

The Company has established that operation of the proposed project would result in reductions in regional emissions of NOx, SO2, and CO2, including reductions in emissions of SO2 and NOx that exceed the proposed facility's own emissions. The Siting Board finds that, on balance, the Company has established that there will be a need in New England for 360 MW of additional energy resources from the proposed project for environmental purposes in the years 2000 through 2005.

b. Massachusetts

i. Description

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

The Company's analysis demonstrated an emissions savings for all pollutants in the 2000-2005 time period (Exhs. MPP-13, exhs. 2.4-5 (rev. A), 2.4-6 (rev. A), 2.4-7 (rev. A)). Specifically, the Company's analysis showed total reductions over the six years of: (1) 4.5 tons of SO2, or 0.64 percent of Massachusetts SO2 emissions; (2) 2.40 tons of NOx, or 0.96 percent of Massachusetts NOx emissions; and (3) 2.80 millions of tons of CO2, or 1.55 percent of Massachusetts CO2 emissions (id.).

ii. Analysis

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

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

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

5. Conclusions on Need

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

or more of additional energy resources in Massachusetts for reliability purposes beginning in the year 2000.

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

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

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

B. Alternative Technologies Comparison

1. Standard of Review

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

In implementing its statutory mandate, the Siting Board requires a petitioner to show that, on balance, its proposed project is superior to alternate approaches in the ability to address the previously identified need in terms of cost, environmental impact and reliability. Berkshire Power Decision, 4 DOMSB at 304; Cabot Decision, 2 DOMSB at 334; Altresco Lynn Decision, 2 DOMSB at 107.

2. Identification of Resource Alternatives

a. Description

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

The Company stated that it used a three-phase screening process to examine all reasonable alternative technologies, and that, as a first step, it compiled a list of those technologies able to meet the identified need based on reliability considerations (Exh. MPP-0, at 3-2 to 3-3). The Company stated that it considered reliable technologies to be those which the 1993 Technical Assessment Guide ("TAG") classified as "Mature" or "Commercial" (id.).(58) The Company indicated that its initial review of the 1993 TAG resulted in a list of 14 potentially viable technologies: GTCC; pulverized coal ("PC"); atmospheric fluidized bed ("AFB"); pressurized fluidized bed ("PFB"); coal gasification-combined cycle ("CGCC"); combustion turbine-simple cycle; fuel cells; geothermal; solar-photovoltaic; wind; municipal refuse-fired; biomass/wood-fired; nuclear; and energy storage (id.). The Company indicated that five technologies rated other than mature or commercial were eliminated from further consideration (id. at 3-3 to 3-5). USGen stated that the 1993 TAG classified the five eliminated alternatives, PFB, CGCC, fuel cell, geothermal and wind, as "demonstration" technologies (id.).

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

Technology Eliminated Rationale

Combustion Turbine-Simple Cycle Not cost effective for baseload operation
Solar-Photovoltaic Insufficient land area to meet the identified need; incompatible with baseload operation
Municipal Refuse-Fired Permitting/schedule constraints; construction of ten 40 MW units is not feasible; site area limitations

Biomass/Wood-Fired Insufficient local resources; site area limitations
Nuclear Permitting/schedule constraints
Energy Storage Not cost effective for base load operation; site limitations

(id.)

The Company indicated that, on the basis of its phase two criteria, the list of potential technology alternatives to the proposed project was narrowed to the GTCC,(59) AFB and PC technologies (id. at 3-8 to 3-9). With respect to the three technologies selected for further analysis, the Company provided the following information: (1) the natural gas-fired GTCC unit generates 225 MW, incorporates selective catalytic reduction ("SCR"), operates at a full load heat rate of 7,300 Btu/kWh and has an equivalent availability of 88.9 percent; (2) the coal-fired, circulating AFB generator produces 200 MW, incorporates limestone injection to control SO2 and particulate matter ("PM") emissions, respectively, operates at a full load heat rate of 9,796 Btu/kWh and has an equivalent availability of 90.4 percent; and (3) the PC unit produces 300 MW, incorporates a spray dryer to minimize SO2 and a fabric filter to control PM, operates at 9,580 Btu/kWh and has an equivalent availability of 85.5 percent (id. at 3-5 to 3-6; EFSB RR-31). The Company stated that in analyzing alternative approaches to the proposed project it scaled the capacity of each alternative technology to that of the proposed project according to EPRI-developed procedures (Exh. MPP-0, at 3-2).(60) Thus, in addition to the proposed project, the Company advanced three technology alternatives, one gas-fired and two coal-fired, to the third phase of its technology alternatives analysis (id. at 3-8 to 3-9). The Company indicated that the third phase of its analysis compared the environmental impacts and costs of the technology alternatives to those of the proposed project (id.).

b. Analysis

The record demonstrates that USGen narrowed the number of potential alternative technologies from fourteen to three in two stages. In the first stage, the Company appropriately reviewed a wide range of potential generation and storage technologies and, based on reasonable criteria, narrowed its review to include nine technologies encompassing a range of technology types and fuels. In the second stage, the Company reviewed these nine technologies and eliminated technologies failing to meet one or more of the Company's stated criteria. The record also demonstrates that the Company used standard industry procedures to scale each evaluated alternative technology to the size of the proposed project.(61)

Thus the record demonstrates that all facilities have been evaluated based on the same output and criteria. The Company has appropriately identified three technology

alternatives and two different fuels capable of meeting the identified need in lieu of the Company's proposed project. The Siting Board finds that the proposed project, a GTCC alternative, a coal-fired AFB alternative and a PC alternative are comparable in terms of their ability to meet the identified need. Therefore, in reviewing the cost and environmental impacts of the proposed project, the Siting Board compares the proposed project to each of three technology alternatives: GTCC, AFB and PC.

3. Environmental Impacts

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

The Company stated that, to the extent possible, the alternative technologies and the proposed project were compared based on the same level of net electric output, 360 MW, and assumed to begin commercial operation at the same time, in January of the year 2000 (Exhs. MPP-0, at 3-5; MPP-11, at 8-9; MPP-11, att. 4). The Company indicated that it gathered the bulk of its cost and performance data from vendors for the proposed project and from the 1993 TAG for the technology alternatives (Exh. MPP-0, at 3-5).(62)

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

a. Air Quality

The Company asserted that the proposed project would be preferable to the three alternative technologies with respect to air quality (Exh. MPP-0, at 3-13, 3-15). In support of its assertion, USGen provided an analysis of the average annual emission rates and the annual amount of emissions of SO2, NOx, PM-10, carbon monoxide ("CO"), volatile organic compounds ("VOCs") and CO2 for the proposed project and the technology alternatives (Exh. EFSB RR-29, Table 3.4-1 (rev. A)). In calculating emission rates for the proposed project and the GTCC alternative, the Company assumed use of back-up oil with 0.05 percent sulfur content for 720 hours per year (id.).(63) The Company also assumed that the GTCC alternative would meet the same emissions control standards as the proposed project and would therefore have the same emission rates as the proposed project (Exh. MPP-0, at 3-13).

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

USGen indicated that the proposed project would produce fewer annual air emissions of SO2, NOx, PM-10, CO, VOCs and CO2 than would all evaluated alternatives (Exhs. MPP-0, at 3-13; EFSB RR-29, Table 3.4-1 (rev. A)). The Company further stated that, although the average annual emission rates of the proposed project and the GTCC alternative are comparable, the annual emissions from the proposed project would be lower, reflecting its lower heat rate (Exhs. MPP-0, at 3-13; EFSB RR-29, Table 3.4-1 (rev. A)). See Table 3, below.

Table 3

Alternative Technologies - Pollutant Emissions

	Mil-GTCC	GTCC	PC	AFB
Ann. average emission rates (lbs/MMBTU)				
SO2	0.0100	0.0101	0.2	0.225
NOx	0.0154	0.0155	0.17	0.15
PM-10	0.0060	0.0061	0.018	0.018
CO	0.0253	0.0253	0.11	0.13
VOC	0.0017	0.0017	0.0036	0.006
CO2	117	117		

204
204

Ann. emissions (tpy), based on assumed availability factor
Availability Factor 91.7%
88.9%
85.5%
90.4%

SO2 94
95
1880
2115

NOx 145
159
2196
2095

PM-10 56
62
232
251

CO 237
258
1421
1815

VOC 16
17
46
84

CO2 (1,000 tpy) 1,096
1,195
2,635
2,849

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

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

b. Water Supply and Wastewater

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

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

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

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

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

c. Noise

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

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

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

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

d. Fuel Transportation

USGen asserted that the proposed project is slightly preferable to the GTCC alternative and superior to the coal-fired alternatives with respect to fuel transportation impacts (Exh. MPP-0, at 3-17 to 3-18). USGen stated that natural gas would be delivered to the site via an existing high-pressure interstate pipeline which borders the proposed site (Exh.

MPP-0, at 3-17). The Company stated that the proposed project will also require fuel oil deliveries when back-up fuel is used (id.). The Company stated that fuel oil would be delivered by truck, deliveries to be scheduled as necessary for refilling (id.). The Company indicated that the unloading rate of oil at the proposed project would not exceed three trucks per hour, and that use of fuel-oil would not exceed 720 hours per 12 month rolling period (id.). The Company stated that the GTCC alternative would have comparable fuel delivery requirements but that, due to its higher heat rate, the GTCC alternative would require greater quantities of natural gas and a greater number of oil deliveries (id.; Exh. EFSB RR-31, Table 3.4-3 (rev. A)).

The Company stated that the PC alternative would use less coal than the AFB alternative and that coal delivery for the PC alternative would fill 10,332 rail cars per year (Exh. EFSB RR-31, Table 3.4-3 (rev. A)). The Company explained that, given a typical 100-car train, this would require the arrival and departure of over 104 trains per year, or two per week (id.; Exh. MPP-0, at 3-19). The Company stated that the AFB and PC alternatives would also require truck delivery of limestone or lime for SO2 control (Exh. MPP 3-19). The Company explained that it selected the proposed site in part due to its proximity to an existing natural gas pipeline in order to minimize the impacts of gas transportation (id.). The Company noted that the preferred site has no rail access and that a coal-fired project would likely be sited in close proximity to existing rail lines with adequate capacity to accommodate coal deliveries in order to minimize impacts of fuel transportation (id.). The Company stated that, even assuming the availability of adequate rail infrastructure, delivery of coal by rail to the proposed site would still involve impacts to other users and to abutting communities (id.; Tr. 8, at 81 to 82.).

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

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

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

e. Land Use

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

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

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

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

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

f. Solid Waste

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

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

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

g. Findings and Conclusions on Environmental Impacts

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

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

4. Cost

a. Description

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

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

that it also assumed that the proposed project and each alternative would run constantly, limited only by its individual equivalent availability factor (id. at 3-9).

Table 4, below, details the total installed costs, O&M costs, and the 20- and 30-year levelized cost for the alternative technologies. USGen indicated that both the 20- and 30-year levelized cost of the proposed project would be significantly lower than that of the alternative technology units (id. at 3-9, 3-11; Exhs. MPP-11, att. 4, Table 3.2-2 (rev. A); EFSB A-6a (rev.); Tr. 8, at 58 to 59).

Table 4

TECHNOLOGY PARAMETERS AND LEVELIZED COSTS

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

1. 1995 fuel prices for gas-fired units are based on 100 percent load factor.

2. Total Plant Investment includes total cost of plant, permitting, land, interconnection, AFUDC, start-up and inventory, and working capital.

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

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

b. Analysis

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

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

5. Reliability

a. Description

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

The Company stated that projects that rely on a mature, commercially available technology have a reliability advantage over technologies whose expected cost and performance characteristics have yet to be fully demonstrated and are based primarily on engineering estimates (id.). The Company indicated that the proposed project and the GTCC and PC alternatives use technologies classified as mature in the 1993 TAG, but that the AFB technology is classified as commercial and is therefore somewhat less reliable (id.). The Company stated that the proposed project and the GTCC alternative use essentially the same technology and in this respect, therefore, offer equivalent reliability (id.).(68) The Company also stated, however, that the proposed project would have an anticipated availability of 91.7 percent, higher than any of the other technology alternatives (see Table 4, above) (id.). In addition, the Company stated that it selected the proposed project over the GTCC alternative for reasons of efficiency and the demonstrated performance of the turbine associated with the proposed project (id.). The Company further stated that it has arranged for firm fuel delivery through U.S. Generating Fuel Service ("USGenFS") (Exh. MPP-8, att. 2).(69) Thus, the Company concluded that the proposed project is comparable to the GTCC alternative and superior

to each of the coal-fired units with respect to reliability (Exh. MPP-0, at 3-24; Tr. 8, at 72).

b. Analysis

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

In comparing the reliability of the proposed project to the reliability of the GTCC alternative, the Siting Board notes that the availability factor for the GTCC alternative is assumed to be 88.9 percent, 2.8 percent less than that of the proposed project. Such a difference in availability of the two technologies, while indicating that the proposed project would be slightly preferable to the GTCC alternative, does not represent a significant difference for the purposes of this review. In addition, the GTCC technology is classified as mature by the 1993 TAG. Further the Siting Board assumes comparable fuel supply arrangements for the two technologies. Accordingly, the Siting Board finds that the proposed project and the GTCC alternative would be comparable with respect to reliability.

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

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

In comparing the reliability of the proposed project to that of the PC alternative, the Siting Board notes that the availability factor of the PC alternative is 85.5 percent, 6.2 percent less than that of the proposed project. Such a difference in availability of the two technologies, while indicating that the proposed project would be slightly preferable to

the PC alternative, does not represent a significant difference for the purposes of this review. In addition, both technologies are classified as mature. Accordingly, the Siting Board finds that the proposed project and PC alternative would be comparable with respect to reliability.

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

6. Comparison of the Proposed Project and Technology Alternatives

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

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

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

C. Project Viability

1. Standard of Review

a. Existing Standard

The Siting Board determines that a proposed NUG is likely to be a viable source of energy if (1) the project is reasonably likely to be financed and constructed so that the

project will actually go into service as planned, and (2) the project is likely to operate and be a reliable, least-cost source of energy over the planned life of the proposed project. Dighton Power Decision, EFSB 96-3 at 24; Berkshire Power Decision, 4 DOMSB at 346.

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

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

b. Company's Position

The Company argued that while the proposed project meets the Siting Board's existing standard for viability, the evidence required to demonstrate that an applicant meets that standard should be reconsidered and modified (Exhs. MPP-0, at 4-1 to 4-2; MPP-2,

at 2-12; Company Brief at 30). Specifically, with respect to the first test of viability -- that financing and construction will go forward as planned -- the Company asserted that evidence of a project's competitiveness in the market should be sufficient when coupled with evidence that the proponent has previously financed and constructed a reasonably similar facility within a time frame similar to the proposed schedule and, further, has demonstrated that sufficient financial resources are available for the project (Exhs. MPP-0, at 4-1 to 4-2;

MPP-2, at 6-9; Tr. 2, at 79-83; Company Brief at 31). The Company acknowledged that a detailed review and approval of the terms of a turnkey construction contract ("EPC contract") may still be necessary for developers without a proven project management track record (Tr. 2, at 80-81). However, the Company advocated that where a project proponent has a proven track record in developing comparable facilities and faces substantial project and financial risk if a project fails to materialize on schedule, market forces may be reasonably relied upon as a substitute for Siting Board analysis and approval of the terms of an EPC contract (Exhs. MPP-0, at 4-2; MPP-2 at 9; Tr. 2, at 80-82). Mr. Egan suggested five factors which the Siting Board could use to measure comparability of facilities: size, fuel type, technology, location, and regulatory structure (Tr. 2, at 122-23).

With respect to operational viability, the Company asserted that the Siting Board should review contracts for fuel supply and O&M only when project developers have either a

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

In addition, the Company stated that a long-term, dedicated firm gas transportation contract would negatively impact the viability of the proposed project (Exhs. MPP-7, at 8; EFSB RR-37). Mr. Egan testified that if the Company were required to enter into a

long-term, dedicated firm gas transportation agreement, it would run the risk that over time its fuel costs would become significantly out of market, threatening the viability of the project (Tr. 2, at 89-90, 112-13). The Company therefore argued that the Siting Board should not require USGen to enter into a long-term fuel supply contract with dedicated firm gas transportation arrangements (Exh. MPP-7, at 7-8; Tr. 2, at 81-85, 112-13).

c. Analysis

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

The Siting Board understands USGen's concerns about the proliferation of confidential information in its proceedings. We also note that, in determining whether a proposed NUG project is likely to be viable as a reliable least-cost source of energy over the

planned life of a proposed project, proponents that have relatively little experience in the development of a major generating facility have been asked to establish that experienced and competent entities are contracted for, or otherwise committed to, the performance of critical tasks. Nevertheless, we are hesitant to set forth a specific level of experience that would exempt applicants from a review of their contracts without first hearing arguments from other interested parties as to how such a change might affect the relative competitiveness of potential facility developers, and thus the level of competition in the electric market in Massachusetts.

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

2. Financiability and Construction

a. Financiability

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

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

The Company explained that the proposed facility is to be financed as a merchant plant, without signed long-term power contracts (Tr. 4, at 31). The Company acknowledged that the proposed project would be the first USGen owned facility in the United States to be financed as a merchant plant (id. at 33; Exh. V-29).(71) The Company identified several options that are available to it for financing its proposed project (Exh. MPP-0, at 4-3; Tr. 4, at 33-34). The Company explained that merchant plant financing requires an equity contribution in the 30 to 50 percent range, which is an increase over equity required for conventional methods of independent power producer ("IPP") financing based on long-term contracts (Exh. MPP-0, at 4-3; Tr. 2, at 20). However, the Company asserted that PG&E has access to substantial amounts of capital for equity investment for such projects (Exh. MPP-0, at 4-3; Tr. 4, at 30-31). Further, the Company reported that the equity component of the project would be financed internally, and that the Company would only need to secure the debt necessary for the project (Tr. 4, at 33). Finally, the Company asserted that the fact that it has a high level of equity capitalization in the project serves to mitigate potential risks that could arise during financing (id. 4, at 43).

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

To demonstrate financiability under conventional financing, the Company provided pro forma analyses based on four price forecasts: high, base, and low case forecasts submitted to the New Hampshire Public Utilities Commission ("New Hampshire PUC")(72) and a New England Electric System ("NEES")/NEPOOL price forecast (id. at 25-26;

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

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

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

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

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

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

significant experience in power sales transactions. Further, the Company has actively sought to contact financing institutions regarding the potential of merchant plant financing.

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

b. Construction

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

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

The Company has submitted a sample EPC contract, including terms the Company generally expects to include in any final EPC contract (Exhs. EFSB V-12 (supp. A);

EFSB E-116). The sample EPC contract provides the owner with a fixed price for the proposed project based on an agreed scope of work (Exh. EFSB V-12 (supp. A)). The Company stated that, according to the sample EPC contract, BPC would be responsible for all design, engineering, procurement, delivery, construction tasks, installation and training needed to bring the plant into operation at guaranteed output, heat rate, emissions, noise and other performance levels (id.). The Company explained that the sample EPC contract, which is a precursor to the EPC contract, contains a set of binding terms and conditions for the engineering and construction of the proposed facility, including provisions for: (1) a fixed price with monthly progress payments to the contractor; (2) a guaranteed schedule;

(3) liquidated damages for failure to achieve (a) substantial completion by the guaranteed completion date, or (b) operation guarantees; (4) bonuses for early completion and

improved performance; (5) warranties; (6) insurance; and (7) performance and facilities testing (id.).

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

The Company also asserted that Westinghouse has guaranteed an equipment delivery schedule which will support a commercial operation date for the proposed project of June 1, 2000 (Exh. MPP-11 at 4). The Company stated that a detailed term sheet was negotiated and executed with Westinghouse for the 501G combined cycle configuration to be supplied for the project (Exh. EFSB V-9 (rev. A)). The Company reported that output and heat rate for the equipment are guaranteed with liquidated damages to be assessed if the guaranteed levels are not achieved and that the agreement with Westinghouse provides for a reliability run performance test (id.). The Company stated that the availability projected for the life of the facility is approximately 92 percent, which is well within industry standards (id.). Further, the Company indicated that if necessary, the Mitsubishi unit could be employed at the same cost, and that the schedule contains the flexibility to accommodate such a change (Tr. 2, at 132-133).

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

The Company indicated that it has been notified by NEPSCo that the reliability of the W-123 circuit exceeds 99 percent, as the forced outage rate of the W-123 line was 1.5 minutes over the past five years (Exh. RR-40, supp. A). The Company stated that the reconductoring of the W-123 line would be completed in time to meet the identified need

in the summer of 2000, and would serve as a viable transmission link for the planned life of the facility (Exhs. MPP-18, at 3-4; MPP-37, at 1-2 Tr. 10, at 5-6).

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

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

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

Finally, the Siting Board notes that the proposed the 501G turbine began commercial operation in June of 1997, and therefore has limited operating experience. While the record indicates that Westinghouse would be responsible for correcting any problems with the turbine, the proposed project cannot go forward as planned if there are unexpected delays in turbine development or testing. The Siting Board notes, however, that the time between commercial operation of the Mitsubishi 501G turbine and the operation of the Millennium project is at least two years. Because the Westinghouse 501G turbine is virtually identical to the Mitsubishi 501G turbine commercial testing for one is indicative of the operating capability of the other. Moreover, the Company has

indicated that the Mitsubishi 501G turbine could be substituted for the Westinghouse 501G turbine if necessary to meet the

on-line date. The Siting Board reiterates that a project proponent has an absolute obligation to construct and operate its facility in conformance with all aspects of its proposal (see Section IV, below). Should the 501G turbine, in either the Westinghouse or Mitsubishi configuration, be unable to perform substantially as expected, USGen would be required to notify the Siting Board as explained in Section IV, below.

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

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

3. Operations and Fuel Acquisition

a. Operations

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

at 337-339; Altresco-Pittsfield Decision, 17 DOMSC at 382-383.

The Company stated that it plans ultimately to negotiate a contract, complete with penalty and incentive provisions, with U.S. Operating Service Company ("USOSC"), an experienced O&M contractor (Exh. MPP-0, at 4-7). Here, the Company has provided a sample O&M agreement with USOSC for illustrative purposes, to show the types of considerations the Company has included for comparable contracts in the past

(Exh. EFSB V-13). The Company stated that it is important to maintain flexibility in the terms of the agreement at this point in the development process in order to allow the project to adapt to market conditions throughout the development process, optimizing its efficiency (Tr. 3, at 53-55). The Company further explained that O&M contracts for merchant plant facilities would be less prescriptive in their intended goals and expectations of the operator, insuring the necessary degree of flexibility (id. at 46).(77)

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

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

In past cases, the Siting Board has found that an acceptable, executed O&M contract with an appropriate, experienced entity provided sufficient assurance that a project is likely to be operated and maintained in a manner consistent with reliable performance objectives. Dighton Power Decision, EFSB 96-3 at 28; Berkshire Power Decision, 4 DOMSB at 338; Altresco-Pittsfield Decision, 17 DOMSC at 382. The Siting Board notes that the Company has provided a sample O&M contract and accepts that the Company's and USOSC's experience in operating, maintaining, and managing comparable facilities is strong evidence that the Company will be able to negotiate an acceptable final O&M contract. The Siting Board notes that the Company has stressed its intention to provide low-cost, clean power and has stated that its O&M practices would be structured to fulfill these objectives. However, while the record supports an expectation that USGen will

contract for a low cost, clean power project, it does not include a final O&M contract. Therefore, the Siting Board requires USGen to provide the Siting Board with a copy of a signed O&M contract between USGen and USOSC or a comparable entity, that contains provisions that would provide reasonable assurance that the project would perform as a low-cost, clean power producer.

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

b. Fuel Acquisition

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

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

(Exh. MPP-0, at 4-7; Tr. 3, at 71-72).

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

To provide for on-site delivery of natural gas to the facility from the TGP mainline, the Company stated that it has entered into discussions with TGP and other third-party contractors to bid competitively for the construction of a high pressure lateral to the facility (Exh. MPP-0, at 4-8). The Company asserted that sufficient capacity exists on the TGP system in the area of the project to ensure a reliable gas supply (Exhs. EFSB V-16;

EFSB V-36).(79) The Company noted that because it would contract for natural gas to be delivered to the facility at the interconnection with the TGP, the burden of maintaining transportation capacity on the TGP system to ensure firm gas deliveries would reside with the supplier, USGenFS (Exh. MPP-0, at 4-8; Tr. 3, at 78). The Company stated that by relying on USGenFS, it would avoid the increased cost associated with contracting for firm pipeline capacity as well as any other associated pipeline demand charges and/or supplier demand charges which, in turn, would allow USGen to maximize the benefit of the proposed project to the customer(80) (Exhs. MPP-0, at 4-8; MPP-7, at 4).

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

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

The Company indicated that it would retain a three-day supply (approximately 25,000 barrels ("bbls")) of No. 2 fuel oil on-site (Exh. MPP-7, at 6). The Company stated that USGenFS has entered into supply discussions with Coastal Oil Marketing and Sprague Energy, both of which maintain distillate fuel oil terminals in the greater Boston and New England area, and would use local tanker truck transportation in order to deliver distillate fuel oil to the site (Exhs. MPP-0, at 4-8 to 4-9; EFSB V-18a). The Company explained that in addition to constructing on-site off-loading facilities, it has entered into

discussions with various third-party contractors to competitively bid and construct a fuel oil lateral which will connect with the Mobil Oil Products line adjacent to the TGP mainline and the facility site (Exhs. MPP-8, at 8-9; EFSB V-18a). The Company asserted that whenever practical, it will access and use excess space in the Mobil Oil Products line to deliver distillate fuel oil to the facility, and that it expects that the pipeline would be used for off-peak deliveries (Exh. EFSB V-18a; Tr. 3, at 74).

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

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

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

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

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

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

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

The Siting Board acknowledges that there is a benefit to the flexible gas procurement approach contemplated for the proposed project. In this case, the Company has elaborated on the additional costs, both in dollars and lost efficiency, that would be associated with a dedicated long-term firm gas transportation contract. Further, the Company has demonstrated that it has experience in procuring fuel for comparable facilities, and that its projected supplier, USGenFS, has substantial experience in delivering fuel to comparable facilities. In addition, the Siting Board recognizes that USGenFS, by virtue of its size and scale in the marketplace, has an enhanced ability to supply gas on a long term basis. Consequently, the Siting Board will not require USGen to enter into a firm transportation contract for the proposed project.

However, the Siting Board notes that at this point in time, the industry is in a period when the demand for and the supply and deliverability of natural gas in New England are in flux. This is the first case reviewed by the Siting Board in which the petitioner plans to rely on delivery of gas to a project delivery point on an interstate pipeline without a firm transportation arrangement for any portion of a supply route. While the Company has described a number of projects that would increase gas capacity into New England, these projects are, for the most part, still in the planning and permitting stages. Moreover, future generating facilities also must be factored into any calculation of future supply and

demand for gas delivered to New England. As discussed in the need analysis above (see Sections II.A.2. and II.A.3) sustained generating capacity expansion is expected for at least the first six years of the life of the proposed project, with new gas-fired power plants as the principal sources of the supply assumed in the Company's need analysis. Consequently, increased demands on the existing gas supply system are very likely. In the absence of a dedicated transportation arrangement, the Siting Board cannot be certain that USGen's fuel supply strategy will continue to be viable at the time that project construction commences.

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

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

The Siting Board has found that the Company has established that (1) upon compliance with the condition relative to providing a signed O&M contract, the proposed project is likely to be operated and maintained in a manner consistent with appropriate performance objectives, and (2) upon compliance with the condition relative to an annually updated fuel acquisition assessment, its fuel acquisition strategy reasonably ensures a

low-cost, reliable source of energy over the planned life of the proposed project. Accordingly, the Siting Board finds that the Company has established that its proposed project meets the Siting Board's second test of viability.

4. Findings and Conclusions on Project Viability

The Siting Board has found that upon compliance with the conditions in Sections II.C.2.b, II.C.3.a, and II.C.3.b, above, USGen will have established that (1) the proposed project is reasonably likely to be financed and constructed so that the project will actually

go into service as planned, and (2) is likely to operate and be a reliable, least-cost source of energy over the planned life of the proposed project.

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

III. ANALYSIS OF THE PROPOSED FACILITIES

A. Site Selection Process

The Siting Board has a statutory mandate to implement the energy policies in G.L.

c. 164 §§ 69H-69Q to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. G.L. c. 164 §§ 69H and 69J. Further, G.L. c. 164 § 69J requires the Siting Board to review alternatives to planned projects, including "other site locations." In implementing this statutory mandate and requirement, the Siting Board requires a petitioner to show that its proposed facilities' siting plans are superior to alternatives and that its proposed facilities are sited at locations that minimize costs and environmental impacts while ensuring supply reliability. Dighton Power Decision, EFSB 96-3 at 31; Berkshire Power Decision, 4 DOMSB at 347; 1993 BECo Decision, 1 DOMSB at 27.

1. Standard of Review

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

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

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

2. Development and Application of Siting Criteria

The Company indicated that its initial site selection process was designed to: (1) identify a reasonable universe of site alternatives; (2) identify a consistent set of objective site evaluation criteria; and (3) select from the universe of sites the site for the proposed project that was least cost, with the least environmental impacts (Exh. MPP-0, at 5-1). The Company indicated that its site selection process consisted of three phases: Phase I, the identification, screening, scoring and ranking process; Phase II, environmental investigation and project definition; and Phase III, evaluation, and testing of public and regulatory acceptance of the proposed project (Exh. MPP-42, att. 1; Tr. 10, at 53-57).(84)

a. Description

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

The Company explained that it developed two types of site selection criteria (1) threshold criteria that each site was required to meet in order to be further considered as a site for the proposed facility, and (2) more detailed screening criteria (Exh. MPP-0,

at 5-5). The Company stated that its threshold criteria included: (a) limitation to location(s) within three miles of the intersection of an electric transmission line of at least 115 kV and a portion of the TGP system sized over 20 inches in diameter;(86) (b) a

minimum site size of at least 15 buildable acres; (c) suitability for industrial development; and (d) accessibility to roadway infrastructure (id. at 5-5).

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

The Company stated that it used 12 detailed screening criteria to rank the eight selected sites: (1) proximity to gas pipelines; (2) proximity to electric transmission line;

(3) site size and buffering potential;(88) (4) site zoning designation; (5) adequacy of roadway infrastructure; (6) water availability; (7) topography; (8) wetlands/waterbodies; (9) potential for site contamination; (10) air quality dispersion environment; (11) proximity to sensitive receptors;(89) and (12) wastewater disposal availability (id. at 5-18 to 5-24).

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

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

The Company stated that it has a policy of evaluating community acceptance as part of the siting process (Tr. 10, at 80). The Company explained that during Phase I of its site selection process, it met with town officials and elected representatives, including the

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

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

The Company further stated that once enough information had been collected to prepare the ENF, it was ready to test the receptiveness of the broader community to the project as part of Phase III of the site selection process (Exh. MPP-41, at 5).(95) The Company reported that during June, July and August 1996, its representatives met with the local newspapers, participated in public meetings or hearings and otherwise presented information about the project and evaluated public reaction to the project (id.; Exhs.

MPP-42; MPP-44; Tr. 10, at 72-75). The Company also reported that it experienced positive community reactions (Tr. 10, at 75). The Company indicated that if it had encountered a high degree of public opposition by public officials who were approached earlier, the Company would have revisited its selection of the preferred site (id. at 57, 88). The Company stated that it was only after Phase III was completed in August 1996 that the Company made the final decision on site selection (Exh. MPP-41, at 5).

b. Analysis

The Siting Board notes that the majority of its past generation facility reviews have concerned cogeneration facilities. However, the Siting Board previously has stated that the site selection criteria developed for an IPP should be similar to criteria developed for a cogeneration facility, except for the steam host locational requirement. Berkshire Power

Decision, 4 DOMSB at 351; Enron Decision, 23 DOMSC at 127. Here, the Company has developed a broad array of criteria which address the critical issues associated with the siting of generating facilities and which are generally consistent with site selection criteria which the Siting Board has found to be appropriate in previous reviews. Berkshire Power Decision, 4 DOMSB at 349-351; Cabot Decision, 2 DOMSB at 380-381; MASSPOWER Decision, 20 DOMSC at 378-379.

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

The Siting Board acknowledges that proximity to a sensitive receptor is a contributing factor to both the noise and visual impacts (see Sections III.B.2.d and III.B.2.c, below). However, noise impacts are a function of both distance and ambient noise levels,(97) while visual impacts are a function of screening and topography, as well as distance.(98) Evaluation of the single criterion, distance to sensitive receptors, may therefore result in a misstatement of the project's likely noise and visual impacts. Moreover, noise and/or visual impacts have often proven to be among the most significant environmental issues in generating facility cases (see Sections III.B.2.d and III.B.2.c, below). See Dighton Power Decision, EFSB

96-3 at 47-48, 55-58; Berkshire Power Decision, 4 DOMSB at 394-396, 403-406; Enron Decision, 23 DOMSC at 210-212, 223. Therefore, the Siting Board will require future proponents, at the site screening level, to assess visual impacts based on vegetative and other screening potential as well as proximity to sensitive receptors, and assess noise impacts based on indicators of background noise as well as proximity to sensitive receptors.(99)

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

The record also indicates that the Company did not seek community input regarding the proposed site from neighboring residents until Phase III of its site selection process, after initial regulatory filings had been made. The Siting Board previously has recommended

that both the local community and local government be included in an open, participatory site selection process from the inception of a project. Berkshire Power Decision, 4 DOMSB at 356; Altresco Lynn Decision, 2 DOMSB at 173. In response, USGen has argued that it is more effective to present a project to the community, and seek its support, after a specific site has been selected and preliminary design work and environmental studies have been completed. The Siting Board hereby clarifies its recommendations regarding community input into the site selection process, in light of USGen's comments.

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

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

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

c. Geographic Diversity

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

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

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

3. Conclusions on Site Selection Process

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

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

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

1. Standard of Review

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

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

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

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

potential mitigation measures in order to make such a determination.(100) Berkshire Power Decision, 4 DOMSB at 359; Silver City Decision, 3 DOMSB at 277; 1993 BECo Decision, 1 DOMSB at 39-40, 154-155, 197. The Siting Board can then determine whether environmental impacts have been minimized. Similarly, the Siting Board must find that the project proponent has provided sufficient cost information in order to determine if the appropriate balance among environmental impacts, costs, and reliability has been achieved. Berkshire Power Decision, 4 DOMSB at 359; Silver City Decision, 3 DOMSB at 278; 1993 BECo Decision, 1 DOMSB at 40.

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

2. Environmental Impacts

a. Air Quality

i. Applicable Regulations

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

The Company indicated that under NAAQS, all geographic areas are classified as attainment, non-attainment or unclassified for six criteria pollutants: SO2, PM-10, NOx, CO, ground-level ozone ("O3") and lead ("Pb") (Exh. MPP-0, at 6-4). The Company further indicated that, although the Charlton area is classified as "attainment" or "unclassified" for SO2, PM-10, NOx, CO and Pb, the entire Commonwealth of Massachusetts is in serious non-attainment for O3 (id.).

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

The Company further indicated that under NSR requirements, the proposed facility must apply Lowest Achievable Emission Rate ("LAER") technology and emissions offsets to any directly emitted pollutant which is a precursor to O3, and which the proposed facility may emit at levels greater than 50 tpy (Exhs. MPP-0, at 6-5; MPP-4, att. 6 (rev.) at 5-1). Thus, the Company must apply LAER technology to control NOx (see Table 3) (Exh. MPP-0, at 6-5). With regard to NSPS requirements, the Company indicated that emissions of regulated pollutants -- NOx and SO2 for the proposed facility -- would fall significantly below those levels (Exhs. MPP-0, at 6-5; MPP-4, att. 6 (rev.) at 5-1).

In addition, the Company noted that the proposed facility would also incorporate BACT for SO2, Pb, VOCs and air toxics, pollutants regulated as part of the MDEP air plans approval process (Exhs. MPP-0, at 6-6; MPP-4, att. 6 (rev.) at 4-1).

ii. Primary Site

(A) Emissions and Impacts

The Company indicated that the proposed facility would emit regulated pollutants, including criteria and non-criteria pollutants, and CO2 (Exh. MPP-4, at 4-8 to 4-14). The Company asserted, however, that air quality impacts from the proposed facility would be minimized through the use of efficient technology, advanced pollution control equipment, clean fuels, and acquisition of NOx offsets (Exh. MPP-0, at 6-2, 6-22, 6-24). The Company also asserted that dispatch of the proposed project in preference to older, oil-fired generating plants would result in NOx, SO2 and CO2 displacement (id. at 6-24).

The Company estimated the quantity of pollutants that would be emitted from the proposed facility on the basis of information from government data centers, from manufacturers and vendors of equipment and from literature reviews (Exhs. MPP-4, att. 6, App. B; EFSB E-18(b) (rev. A); Tr. 8, 117-120). The Company provided calculations of air emissions for the proposed facility based on firing low-sulfur distillate oil for 720 hours and natural gas for the remainder of the year, both at 100 percent load (Exhs. MPP-4, att. 6, at 5-7, 5-9; MPP-14, att. 1, at 1).(103) The Company asserted that, because it would operate as a merchant power plant, the proposed facility would require the ability to use oil for up to 720 hours per year (Exh. MPP-0, at 4-7 to 4-8).(104)

The Company maintained that its proposed facility would incorporate BACT for CO, PM-10, SO2, Pb, and VOCs, as well as both BACT and LAER for NOx (Exhs. MPP-4, att. 6, at 4-8, 4-12; MPP-4, att. 6 (rev.) at 4-1 to 4-3). The Company further maintained

that emission rates for non-criteria pollutants and sulfuric acid would also represent BACT (Exh. MPP-4, att. 6, at 4-12 to 4-13; MPP-4, att. 6 (rev.) at 4-3 to 4-4). In support of its contention that assumed facility emission rates would represent BACT and/or LAER for the identified pollutants, the Company provided information regarding control options for the proposed facility (Exh. MPP-4, att. 6, at 4-8 to 4-14).

The Company asserted that predicted air pollutant concentrations resulting from emissions from the proposed facility would be "insignificant" relative to ambient air quality standards (id.; Exh. MPP-14, att. 1, at 2). In support of its assertion, the Company provided local air quality modeling results(105) indicating that impacts of the proposed facility on ambient concentrations of criteria pollutants would be below SILs, assuming a stack height of 225 feet (Exhs. MPP-4, att. 6, at 5-1; MPP-4, att. 6 (rev.) at 5-2: EFSB E-50; EFSB E-52).

The Company presented a displacement analysis for the six-year period 2000 to 2005, indicating that regional emissions of SO2, NOx and CO2 would be less with construction and operation of the Millennium project than without the proposed facility. For the two criteria pollutants SO2 and NOx, the six-year reductions in regional emissions would be several-fold larger than the proposed facility's own emissions over the same period. See Section II.4, above.

The Company also provided predicted ambient concentrations of air toxics from the proposed facility (Exh. EFSB E-36 (rev.)). The Company indicated that the concentrations were derived by scaling from the refined level ISCST2 and CTSCREEN model results for SO2 (Exh. MPP-4, att. 3, at 7-20).(106) Based on its analysis, the Company stated that concentrations of air toxics from the proposed facility with a 225-foot stack would be below applicable standards(107) for all cases (Exhs. EFSB E-36 (rev.); MPP-0, at 6-17).

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

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

likely settle on site, and would have no significant environmental or health impacts (Exhs. EFSB E-25; MPP-4, att. 6, at 4-11 to 4-12; MPP-4, att. 6 (rev.) at 4-3; IP-RR-4).(110)

(B) Offset Proposals

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

The Company indicated that the proposed facility would emit 1,234,801 tpy of CO2 and asserted that the CO2 impacts of the proposed facility would be minimized consistent with Siting Board requirements (Exhs. EFSB E-39 (rev. A); EFSB E-40 (rev. C); Tr. 9, at 30). The Company argued that the displacement of 3.30 million tons of CO2 from other facilities over the period 2000-2005, as a result of the operation and dispatch of the proposed facility, would contribute to the minimization of CO2 impacts from the proposed facility (Exhs. MPP-13, at exh. 2.4-4 (rev. A); MPP-39; Tr. 1, 98; Tr. 9, at 26-29).

The Company proposed a CO2 mitigation donation in the amount of $300,000 in the first year of facility operation (Exh. EFSB E-40 (rev. C); Tr. 9, at 30). The Company explained that this amount reflects an offset of one percent of emissions at up to $1.50 per ton and is consistent with the requirements of the Siting Board set forth in the Dighton Power Decision, EFSB 96-3 at 40 (Exh. EFSB E-40 (rev. C)).(112) However, the Company also indicated that a more appropriate amount would be $231,072 -- the net present value ("NPV") of one percent of emissions at $1.50 per ton over 20 years, assuming three percent inflation each year and a discount rate of ten percent (id.).

In support of its argument that the proposed facility would displace CO2 emissions from other facilities, the Company provided a displacement analysis for the six-year period 2000 to 2005. The analysis showed a six-year reduction in regional CO2 emissions of 3.30 million tons, representing 45 percent of the proposed facility's CO2 emissions of 7.41 million tons over the same period. See Section II.A.4, above.

iii. Alternative Site

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

iv. Analysis

(A) Emissions and Impacts

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

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

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

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

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

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

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

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

(B) Offset Proposals

The Company has presented offset analyses for NOx and CO2 -- pollutants which potentially contribute to regional ozone concerns and national and international climate change concerns, respectively. With respect to NOx, the Company has established that it has a viable plan in place to obtain NOx ERCs consistent with non-attainment NSR and MDEP requirements.

In the Dighton Power Decision, the Siting Board set forth a new approach to meeting CO2 mitigation requirements that requires developers of generating facilities to make a monetary contribution within the early years of facility operation to one or more cost effective CO2 offset programs to be selected in consultation with the Siting Board staff. EFSB 96-3, at 42-43.(114) The Siting Board stated that it expected future contributions to be in the range of Dighton's contribution, which was based on an offset of one percent of facility emissions at $1.50 per ton, to be donated in the early years of the project. Id. at 43. Here the Company has proposed a donation of $300,000 for CO2 offsets, to be provided in one installment, in the first year of facility operation. The Company also presented a displacement analysis indicating that operation of the proposed facility would reduce regional CO2 emissions by 3.30 million tons over the 2000-to-2005 period, offsetting 45 percent of the proposed facility's CO2 emissions.

The Company asserts that the $300,000 donation amount was based on a doubling of the CO2 mitigation requirement in the Dighton Power Decision as the proposed facility will

emit approximately twice as much CO2 as the Dighton Power facility. However, as noted above, the Company indicated that a more appropriate amount would be $231,072, the NPV of offsets over 20 years, calculated at one percent of emissions at $1.50 per ton.

The Siting Board notes that a contribution representing one percent of emissions at $1.50 per ton of CO2, over 20 years, would equal $370,000. Therefore, consistent with the CO2 offset requirement in the Dighton Power Decision, the Siting Board requires the Company to provide CO2 offsets through a donation of $370,000 to be paid in five annual installments of $74,000 during the first five years of facility operation, to a cost-effective CO2 offset program or programs to be selected upon consultation with the Staff of the Siting Board. However, the Siting Board recognizes that the Company may choose to provide the entire donations within the first year of facility operation. If the Company chooses to provide the entire donation within the first year of facility operation, the CO2 offset requirement would be a donation in the amount of $305,000 to a cost-effective CO2 offset program or programs to be selected upon consultation with the Staff of the Siting Board.(115)

Accordingly, the Siting Board finds that implementation of the foregoing NOx and CO2 offset measures would be consistent with a minimization of environmental impacts with respect to air quality.

b. Water-Related Impacts

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

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

The Company compared the use of the proposed evaporative wet cooling tower to four alternative cooling technologies -- a dry cooling system where no water would be required for an evaporative cooling process, two hybrid wet/dry cooling systems and a wet surface air system (Exhs. EFSB E-63; EFSB E-146). The Company stated that,

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

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

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

i. Primary Site

(A) Water Supply

The Company stated that its primary supply for non-potable water would be treated effluent from the Southbridge WWTP, and its supplemental backup supply would be withdrawal from the Quinebaug River (Exh. MPP-0, at 6-53). The Company stated that it has entered into a Memorandum of Understanding ("MOU") with the Town of Southbridge ("Southbridge") whereby Southbridge would make available up to 2.0 mgd of treated effluent to the facility (Exh. EFSB-E-64; Tr. 7, at 95-96).(118) The Company provided a 1996 engineering study completed by Camp, Dresser and McKee ("CDM") which indicated that 2.0 mgd from the Southbridge WWTP would be available for the proposed facility, except during summer drought conditions where between 1.0 and 2.0 mgd would be available (Exh. MPP-0, at 6-57). USGen noted that, for a consistent supply of this volume, the CDM study recommended that a holding tank be provided at the proposed facility and that facility effluent be returned to the headworks of the WWTP (id.).

The Company indicated that the balance of facility non-potable needs, and the full non-potable needs in the event of an interruption of the supply from the WWTP, would be obtained via withdrawal of Quinebaug River water through an existing intake structure located at the American Optical ("AO") facility in Southbridge (Exh. MPP-0, at 6-52). The Company stated that AO is permitted to withdraw up to 11.32 mgd of Quinebaug River water pursuant to a Massachusetts Water Management Act ("WMA") registration, but that AO withdraws less than its permitted amount (Exhs. MPP-4, att. 3 at 12-12; EFSB-E-66a; EFSB E-67).(119) The Company noted that the AO use of the Quinebaug River water for a once through cooling system is nonconsumptive (i.e., the withdrawal volume is returned as wastewater), while the Company's use would be largely consumptive (Tr. 7, at 119-120). Thus, the Company stated that although it has entered

into a transfer agreement with AO for the right to use 2.5 mgd of AO's permitted water withdrawal and to use AO's intake structure, the MDEP has required the Company to file a surface water withdrawal permit pursuant to G.L. c. 21G for approval of its use of the AO-registered water withdrawal (Exhs. EFSB RR-24; EFSB V-47 (supp. B)-A at 3-7 to 3-8; Tr. 7 at 119). The Company indicated the permit application was filed in September 1997 and is currently under review by the MDEP (EFSB V-47 (supp. B)-A at 3-9).

USGen asserted that the Quinebaug River water supply would be reliable, even under dry summer, low flow conditions when use of Southbridge WWTP water could be restricted (Exhs. EFSB E-68; EFSB E-71(b) att. A at 8). USGen explained that the United States Army Corps of Engineers ("ACOE"), pursuant to an agreement with AO, will release upon request up to 10.3 cubic feet per second ("cfs") from the upstream Brimfield reservoir (Exh. EFSB E-68).(120)

The Company acknowledged that the G.L. c. 21G permit likely would contain provisions in the form of a mitigation plan intended to ensure the protection of riverine resources (Exh. EFSB RR-26 (supp.A). The Company stated that it is currently preparing a mitigation plan that may include releases from the Brimfield reservoir by the ACOE (id.). However, the Company asserted that operation of the proposed facility would not have an adverse effect on the Quinebaug River and that any reasonable permit conditions relative to river flow could be met such that the facility operation would not be restricted (Millennium Initial Brief at 27; Exh. MPP-0, at 6-137). In support, the Company provided an analysis of existing conditions of the Quinebaug River and the projected impacts of the proposed facility on river flow, water quality and aquatic ecology within a study area extending from the Westfield Dam, located to the west of the AO facility to a point south of the Massachusetts/Connecticut border (Exh. MPP-0, at 6-61 to 6-107, Fig. 6.3-4).(121) The Company evaluated four facility water withdrawal scenarios(122) under four river flow conditions(123) and compared impacts to existing conditions without the operation of the proposed facility (id.). Based on this analysis, the Company concluded that the Millennium Power project would cause (1) a negligible change in the depth and velocity of flows in the Quinebaug River under all of the modeled scenarios,(124) and (2) minimal water quality changes for the lowest flow and average summer flows(125) (Exhs. MPP-4, att. 3 at 12-57 to 12-73). The Company also concluded that any such changes in river flow and water quality would have negligible impacts on aquatic ecology (id. at 12-79 to 12-86).(126),(127) The Company noted that a Draft Environmental Impact Report ("DEIR") filed in conjunction with a 1991 proposed cogeneration facility at the AO site identified the allowable safe yield of the Quinebaug River to be 16.5 cfs (Exh. MPP-4, Exh. 3, at 2-13, 12-55 to 12-56). The Company also noted that the withdrawal for the proposed Millennium facility would be well within such yield, but that the specific methodology used at that time for calculation of the allowable safe yield has been abandoned by the MDEP (id.).(128) USGen added that its analysis of projected impacts to the Quinebaug River is included in its DEIR and that the Certificate of the Secretary of Environmental Affairs on the DEIR ("Certificate") dated December 16, 1996, indicates that the Company's use of the AO-registered water is not likely to adversely impact the quality of the Quinebaug River (id.).

The Company stated that the proposed facility would access non-potable water via a new water pipeline (Exh. MPP-0, at 1-12). USGen indicated that the new water pipeline would begin at the Southbridge WWTP, travel overland near the Quinebaug River to the AO intake structure, and then traverse industrial property and roadways to reach the primary site (Exh. MPP-0, at 1-13; MPP-14, att. 2). The Company stated that it is has applied for Sewer Connection and Extension Permits from the MDEP in conjunction with its water withdrawal permit under M.G.L. Chapter 21G (Exh. EFSB RR-26 (supp. A).(129)

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

(B) Water-Related Discharges

The Company indicated that the maximum wastewater discharge from the proposed facility would be 1.0 mgd, and that wastewater would flow from the proposed facility to the influent side of the Southbridge WWTP via a new pipeline to be constructed along the same route as the water supply pipeline from the WWTP and AO (Exh. MPP-0, at 1-6 to 1-7, 6-57, 6-60). The Company noted that the wastewater would be retreated in the Southbridge WWTP and discharged to the Quinebaug River (id. at 6-53 to 6-56; Exh. EFSB E-71(b), att. A at 8). The Company indicated that the CDM study found that the Southbridge WWTP would be capable of accepting a 1.0 mgd(130) return flow from the proposed facility until the flow from Southbridge reaches 8.0 mgd (id. at 6-57).(131)

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

The Company indicated that a stormwater management program has been designed to protect surface water resources, vernal pools and other wetland resources on site (Exh. MPP-4, att. 3, at 11-1 to 11-12; Tr. 8, at 29, 37). The Company explained that measures are included in the design of the proposed facility to ensure that post-construction peak

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

(C) Construction Impacts

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

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

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

The Company also indicated that, in order to conform to the industrial zoning of the area, Sherwood Lane, a Town-owned road would be widened (Exh. MPP-4, exh. 3, at 10-29).(139) The Company indicated that the road widening could entail the permanent alteration of 2,125 square feet of wetlands abutting the roadway (Exh. EFSB V-47 (supp.

B)-A at 3-7).(140) The Company noted that remaining wetland areas along the roadway would be protected from construction impacts by the installation of siltation barriers (Exh. MPP-4, att. 5, at 3-1).

The Company indicated that marbled salamanders, classified as a "threatened" species in Massachusetts under the Massachusetts Endangered Species Act, have been observed in a vernal pool within a wetland area located close to the proposed facility footprint (Exh. EFSB E-95A; Tr. 8, at 27). The Company indicated that the Massachusetts Division of Fisheries and Wildlife Natural Heritage and Endangered Species Program ("NHESP") requires a conservation plan which demonstrates that construction of the proposed facility would result in a long-term net benefit to the marbled salamander (Exh. INT-5 (rev. A); Tr. 8, at 27-31). The Company stated that its conservation plan which has been presented to the NHESP includes: (1) permanent protection for the vernal pool and undeveloped mature forest area;(141) (2) construction of three experimental vernal pools creating additional breeding populations; and (3) funding for research on marbled salamanders and evaluation of the experimental vernal pools (Exh. EFSB RR-27 (supp. A).(142) In addition the Company stated that it would relocate the switchyard to minimize facility encroachment on preferable habitat for the marbled salamander (Exh. EFSB V-47 (supp. B)-A at 2-11; Tr. 8, at 28-29).

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

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

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

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

ii. Alternative Site

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

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

iii. Analysis

The record demonstrates that the Company's water supply plan minimizes the use of potable water at both the primary and alternative site by relying on treated effluent from the Southbridge WWTP and additional back-up supplies from the Quinebaug River via an existing intake structure. The record also demonstrates that the Company's water supply plan is likely to be viable. An independent engineering study has confirmed the ability of the Southbridge WWTP to supply treated effluent in the required amounts and the Southbridge WWTP has agreed to supply treated effluent. In addition, AO has agreed to transfer the withdrawal rights for the Company's full water needs under AO's registered withdrawal and the Company has applied to the MDEP for a water withdrawal permit under G.L. c. 21G. The record further demonstrates that dry cooling would significantly reduce the water supply needs of the proposed project but that dry cooling

would increase costs, and also would produce increases in noise and land use impacts, and decrease the efficiency of the proposed facility.

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

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

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

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

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

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

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

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

With respect to construction impacts to wetlands, the record demonstrates that temporary disturbance of wetlands would be greater at the alternative site while permanent alteration of wetlands would be greater at the primary site with consideration of the construction of the site access road. Approximately 1,000 square feet of wetlands would be permanently altered and 3,500 square feet would be temporarily disturbed at the primary site. In addition, construction of the site access road would require additional permanent alteration of approximately 2,125 square feet of wetlands. The Siting Board notes that it is appropriate to consider the wetlands impacts of site access road construction as a project impact, since this upgrade to the Town-owned road is required in order for the proposed facilities to be constructed at the primary site. Approximately 10,800 square feet of wetlands would be temporarily disturbed at the alternative site, with the permanent alteration of 800 square feet of wetlands. In addition, although the Company must receive

a Conservation Permit which must demonstrates a long-term net benefit to the marbled salamander, no threatened species have been identified on the alternative site. Finally, impacts to wetlands and wood turtle habitat due to construction of the water supply and waste water return lines to the primary and alternative sites would be comparable.

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

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

c. Visual Impacts

i. Description

The Company submitted a comprehensive evaluation of potential visual impacts of the proposed facility at the primary and alternative sites (Exhs. MPP-0, at 6-152 to 6-166, 7-24 to 7-35; MPP-4, att. 3 at 6-1 to 6-15; EFSB E-54 to EFSB E-62). As part of its evaluation at each site, the Company conducted a viewshed analysis of the surrounding area (Exh. MPP-0, Figs. 6.7-2,.7.7-1). For each viewshed analysis, the Company identified and mapped areas within two miles of the proposed sites from which the 225 foot stack(145) of the facility might be visible (id.). From areas where the stack had the potential to be visible, the Company selected a number of visual receptor locations on the basis of land use, proximity to site, and potential of impact; the Company added visual receptor locations at the request of the Staff (id. at 6-154, 7-25 to 7-26, Figs. 6.7-2, 7.7-1, Exhs. EFSB E-55 to EFSB E-59; EFSB E-62).(146) The Company presented views both with and without deciduous foliage based on photographs taken from the identified receptor locations looking toward the proposed facility (Exhs. MPP-0, Figs. 6.7-4, 6.7-5; EFSB E-58). The Company then generated a computer-developed perspective of the facility and stack as they would appear from a given receptor and superimposed the perspective on the associated photograph (Exhs. MPP-0, Figs. 6.7-2 to 6.7-12, 7.7-2 to 7.7-9; EFSB E-55 to EFSB E-59; EFSB E-62).

The Company also conducted a plume analysis to assess the conditions and frequency under which plumes were likely to emanate from the main stack and cooling tower of the proposed facility, and the distance from the proposed facility to which visible plumes would likely extend (Exh. MPP-14, att. 1, at 4-6). Based on its analysis, the Company indicated that, over the course of a year, during daylight hours, plumes from the main stack with lengths of 50 meters or more would be visible approximately 20 percent of daylight hours and plumes of 100 meters or more would be visible approximately six percent of daylight hours (id., Table 6.2-10 (rev. A)). The Company also indicated that plumes from the cooling tower of 50 meters or more would be visible approximately 50

percent of daylight hours and that plumes of 100 meters or more would be visible approximately 20 percent of daylight hours (id.). The Company further indicated that plumes from the main stack and cooling tower would be most visible during the winter season and least visible during the summer season (id.). In addition, the Company stated that its plume analysis showed that fog and/or precipitation would be present 73 percent and 52 percent of the time that main stack and cooling tower plumes of 100 meters or longer were present, reducing the visibility of the plumes (Exh. MPP-14, att. 1, at 4). The Company indicated that, while plumes also would be created during nighttime hours, a plume would generally be far less noticeable at night due to the lack of illumination (Tr. 9, at 90-91). The Company indicated that plume visibility above the stack exit location would be the same for the primary and alternative sites (Exh. EFSB E-26).

ii. Primary Site

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

The Company indicated that both the facility structures and the stack would be visible from certain areas to the east of the facility, including portions of Harrington Road in Charlton, and the east side of Route 169 at Sherwood Lane (id. at 6-152, 156, Figs. 6.7-7, 6.7-8, 6.7-12). The Company indicated that approximately six residences on Harrington Road likely would have pronounced views of the proposed facility and that it would be difficult to screen views of the proposed facility from this area (Exh. MPP-0, at Fig. 6.7-8; Tr. 9, at 79-80, 93, 99-101).(147) The Company also stated that the facility structures and the stack would not be visible from the west and that in other directions, visibility would be limited to the top of the stack (Exh. MPP-0, at 156). However, the Company indicated that from some vantage points where the facility itself would not be visible, such as the golf course to the northwest of the site, plumes, when present, would be visible (Tr. 9, at 94-98). The Company provided a copy of the Central Upland section of the most recent Massachusetts Landscape Inventory prepared by the Massachusetts Department of Environmental Management ("MDEM"), which indicates that three areas designated by the MDEM as "distinctive" or "noteworthy" potentially would have views of the proposed facility (Exh. EFSB E-60(a), att. A, E-60(b)).(148) However, the Company stated that the proposed facility would be visible from only one of the three areas, located nearly two miles northeast of the site, and that visibility would be limited to the distant stack, backed by the existing treeline (Exhs. EFSB E-60(b); EFSB E-55(c); MPP-0, Fig. 6.7-2; Tr. 8, at 89-97). The Company maintained that measures to minimize the visual impact of the facility have been included in facility layout, design, lighting and landscaping (Exh. MPP-0, at 152-153; Tr. 9, at 84-85). The Company stated that the

cooling tower would be placed to the west of the HRSG(149) and the main building, thus obstructing the view of the cooling tower from Route 169, and that architectural walls would be placed around the HRSG to enhance its appearance (Exhs. EFSB E-49; EFSB E-51; Tr. 9, at 85). The Company noted that the location of the cooling tower and placement of the architectural wall around the HRSG also would minimize the noise impacts of the proposed facility (Exh. EFSB E-51). The Company also noted that the possible placement of a roof on the HRSG structure, considered as part of an option to achieve higher noise control (see Section III.B.4.a, below) would necessitate increasing the stack height by 50 feet, thus expanding the areas where the proposed facility would be visible (Tr. 8, at 102-106). The Company estimated that within one-half mile of the site, approximately 10 to 50 residences would be affected by an increased stack height (id. at 108).

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

iii. Alternative Site

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

With respect to the Massachusetts Landscape Inventory, the Company stated that the upper portion of the stack would be visible within the area designated as "distinctive" and

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

iv. Analysis

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

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

In implementing its overall plan for off-site shrub and tree planting or window awning installation, the Company: (1) shall provide shrub and tree plantings or window awnings on private property, only with the permission of the property owner and along public ways only with the permission of the appropriate municipal officials; (2) shall provide written notice of this requirement to appropriate officials in Charlton and to all affected

property owners prior to commencement of construction; (3) may limit requests from local residents and town officials for mitigation measures to a specified period ending no less than six months after initial operation of the plant; (4) shall complete all such mitigation measures within one year after completion of construction, or if based on a request after commencement of construction, within one year after such request; and (5) shall be responsible for the reasonable maintenance or replacement of plantings as necessary to ensure that healthy plantings become established. In addition, the Siting Board encourages the Company to work with affected local residents, entities and institutions to develop other reasonable forms of cost-effective visual mitigation.

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

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

d. Noise

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

The Company stated that an increase of three decibels is the minimum increase in average sound level that is perceptible to the human ear (Tr. 6, at 100-101). The Company stated that there are various measures of noise, and indicated that the MDEP guideline which limits allowable noise increases to ten dBA is based on a relatively quiet measure of noise that essentially is the background sound level that is observed in the absence of louder, transient sounds (Exh. MPP-4, att. 3, at 8-4; Tr. 6, at 104). The Company stated that for the purposes of noise analysis in this case, the background level is defined as that level of noise that is exceeded 90 percent of the time ("L90") (Exh. MPP-4, att. 3, at 8-4; Tr. 6, at 102-103, 110).

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

The Company stated that it selected the six monitoring locations in order to project noise increases at the nearest affected residences and property lines (Exh. MPP-4, att. 3, at 8-1 to 8-4. The Company indicated that it performed measurements at three points along Route 169: one directly east of the site at the nearest residences, the Cady Brook Apartments and an adjacent residence, hereinafter referred to as the "Cady Brook Apartments," ("receptor 1"),(153),(154) one located a half mile north of the site ("receptor 5"), and one located a half mile south of the site at the Southbridge town line ("receptor 4")

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

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

With respect to construction noise, the Company provided estimates of maximum levels of construction noise and equivalent levels of such noise at the locations that would experience the largest noise increases, H. Foote Road and Harrington Road (Exh. MPP-0, at 6-174). The Company stated that the maximum noise impact due to construction would be 51 dBA at receptor 6 (Exh. MPP-0, at 6-174). The Company estimated that increases in ambient noise (L90), would range from zero to eight dBA during the excavation and steel erection phases of construction, with lesser increases ranging from zero to four dBA during the remainder of the construction period (Exhs. MPP-0, at 6-174; MPP 4, att. 3 at 8-10, att. 6, at 6-15; EFSB E-2; EFSB E-14; Tr. 6, at 88-92). The Company asserted that construction noise impacts at other locations would be negligible because relatively high daytime background levels, caused by noise from Route 169, would tend to mask construction noise at these locations (Exh. MPP-0, at 6-174).

The Company stated that construction noise impacts would be mitigated by

(1) limiting most construction activity to weekday, daytime periods,(155) and (2) routine inspection and mandatory installation of adequate diesel exhaust mufflers on equipment working at the site (Exh. MPP-4, att. 6, at 6-15).

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

To analyze the noise impacts from operation of the proposed facility, the Company provided estimates of facility noise and combined facility and background noise, by receptor, for daytime and nighttime periods (Exh. MPP-4, att. 3, at 8-12). The Company's model projected that noise contributions from the proposed facility would be 48.3 dBA at

receptor 1, 46.7 dBA at receptor 3, and 43.1 at receptor 6, with lesser amounts at the remaining receptors (id.). The Company's analysis indicated that with facility operation, daytime L90 levels would increase by zero to six dBA at the six receptors, including an increase of 1 dBA to a combined facility and background level of 48 dBA at receptor 1, an increase of 2 dBA to a new level of 46 dBA at receptor 3, and an increase of 6 dBA to a combined level of 42 dBA at receptor 6 (Exh. MPP-4, att. 6, at 6-10, 6-17). The analysis further indicated that with facility operation, nighttime L90 levels would increase by one to ten dBA at the six receptors, including an increase of 10 dBA to a combined level of 48 dBA at receptor 1, an increase of 6 dBA to a combined level of 43 dBA at receptor 2, and an increase of 10 dBA to a combined level of 42 dBA at receptor 6 (id.).

To further analyze the impact of noise from the proposed facility at the residential locations represented by receptors 1 and 2, the Company provided and analyzed facility noise in terms of the L50 metric, or that level of noise that is exceeded 50 percent of the time (Exhs. MPP-4, att. 3, at 8-8, 8-9; EFSB E-135; Tr. 6, at 104; Tr. 7, at 13). The Company projected that at receptor 2 during a typical daytime period, noise from the proposed facility would result in an L50 increase of 3.4 dBA from 41.5 dBA to 44.9 dBA; given that this increase is above the 3 dBA threshold of perceptibility, the Company added that as a result, noise from the plant would be perceptible 50 percent of the time to an observer at this location (Exh. EFSB E-135; Tr. 7, at 14-15). The Company also stated that during the quietest nighttime hour, L50 at receptor 1 would increase by 7.6 dBA, from 41.5 dBA to 49.1 dBA, indicating that noise from the proposed facility would be perceptible at least 50 percent of the time at this location (Exh. EFSB E-135b (rev. A)).

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

The Company asserted that its proposed facility is being designed with careful consideration of measures to mitigate noise impacts in the surrounding community (Exhs. MPP-0, at 6-167; MPP-4, att. 6, at 6-1; Tr. 6, at 86-87). The Company's noise modelling and analysis assumed the incorporation of a series of noise abatement technologies which constituted its "baseline" noise mitigation package for the proposed facility (Exhs. MPP-0, at 6-168; EFSB RR-19; Tr. 7, at 25). Specifically, to mitigate facility noise, the Company stated that the proposed facility would incorporate: (1) a sound absorbing turbine building including 18 gauge siding, four inches of insulation, acoustical louvers and ventilation fan silencers; (2) silencing of air inlets to the combustion turbine; (3) silencing baffles in the HRSG stack to attenuate exhaust noise; (4) use of slow speed or aerodynamically designed low noise fans in the cooling tower; and (5) acoustical barrier walls around the HRSG structure composed of siding and insulation (id.). The Company stated that the total cost of its proposed baseline noise mitigation package (including an operating efficiency penalty of $473,200) would be $2,898,200 (Exh. EFSB RR-19).

The Company stated that its baseline noise mitigation package was designed to bring the proposed facility into compliance with applicable state noise standards, and argued that an L90 increase equal to MDEP's ten-dBA limit would represent an appropriate balance

between mitigation of environmental impacts and costs for the proposed facility at the primary site. The Company further explained that the acoustic design of the facility was largely driven by the noise environment at the closest residential receptor, the Cady Brook Apartments (Exhs. MPP-4, att. 3, at 8-1; EFSB E-11c; EFSB E-134; Tr. 6, at 117-118).

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

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

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

(id. at 21).(159)

In sum, the Company stated that combining the conservatism of the HFF model with that incorporated in the vendor noise guarantees would result in L90 increases that would be overstated in the Company's filing by an amount of three dBA or more (id. at 20-21). The Company stated that it would expect the actual L90 increase at receptor 1 to be three dBA less than that modelled, and that with respect to receptor 6, the increase likely would be overstated by between five and eight dBA (Exh. EFSB E-136; Tr. 6, at 157; Tr. 7, at 19).

In response to requests from the Siting Board staff, the Company identified a number of options to further mitigate the noise impacts of the proposed facility (Exh. EFSB E-11). The Company stated that it developed an option designed to reduce facility noise by an additional three dBA in all directions ("Option 1")(160) (id.). The Company indicated that Option 1 would limit the L90 increase to 7.5 dBA at receptor 1, and would reduce facility noise at other residential locations by two to three dBA below the baseline (id.).

In addition, the Company indicated that, at Harrington Road, Option 1 would limit the L90 increase to 4.4 dBA and additionally would hold L50 increases during typical nighttime periods to less than two dBA, whereas under the baseline mitigation, the increase would be 3.1 dBA (Exhs. EFSB E-11; EFSB E-135b; EFSB E-135b (rev. A)).

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

The Company stated that it developed a second option designed to result in a reduction of facility noise by six dBA below baseline in all directions ("Option 2").(161) The Company indicated that Option 2 would limit the L90 increase from the proposed facility to 5.5 dBA at receptor 1 (Exh. EFSB E-11). The Company stated that Option 2 would include the following mitigation measures: (1) lengthening of silencers in the combustion turbine inlet; (2) lengthening of baffles in the HRSG stack exit; (3) inlet and outlet silencing to reduce cooling tower noise emissions; and (4) full enclosure of the HRSG (Exhs. EFSB

E-11; EFSB E-137; Tr. 7, at 61-67). The Company stated that the total cost of noise mitigation under Option 2 would be $5,509,000,(162) or $2,610,800 more than the baseline cost, and indicated that Option 2 would impose an efficiency penalty of $903,000, or $429,800 more than under the baseline mitigation package (Exh. EFSB RR-19).

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

The Company recognized that the noise increases from operation of the proposed facility would be larger than those previously accepted by the Siting Board (Company Brief at 12). However, the Company argued that additional expenditure on noise mitigation would not be justifiable because it would provide no significant benefits at the most affected locations (id.). The Company argued that noise levels expected at the nearest residences, the Cady Brook Apartments, would not be significantly improved by additional mitigation because the noise environment at this location is dominated by existing sources such as vehicle traffic on Route 169 (id.). The Company asserted that, because of the distinctive noise environment at the Cady Brook Apartments, mitigation of

facility noise would yield less benefit than at locations where background levels are more constant (id. at 13). With respect to noise levels at receptor 6, H. Foote Road, the Company asserted that combining the conservatisms discussed above would result in significantly less facility noise at this location than that projected by the Company's model (Exh. EFSB E-136). As a result, the Company argued that additional expenditures on noise mitigation to control increases at receptor 6 would be unnecessary because, in practice, L90 increases at that location are expected to be significantly less than ten dBA (Company Brief at 14).

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

i. Alternative Site

The Company stated that the proposed facility at the alternative site would require noise mitigation measures beyond those that would be required at the primary site (Exh. MPP-0, at 7-42). The Company indicated that the proposed facility at the alternative site would be designed to mitigate noise impacts and would be consistent with the MDEP ten dBA L90 standard (id. at 7-35). The Company therefore asserted that the proposed facility would have no significant noise impact on the local community (id. at 7-33).

The Company provided analyses of ambient background noise levels and expected noise increases resulting from construction and operation of the proposed facility (Exhs. MPP-0, at 7-35 to 7-42; MPP-4, att. 3, at 8-1). To establish existing background noise levels, the Company surveyed ambient sound levels at two locations representing noise sensitive receptors. The Company stated that residences located along Burlingame Road ("location 1"), would be the closest receptors to the west of the site, and that residences along Flint Road ("location 2"), would be the closest receptors to the east of the site (Exh. MPP-0, at 7-36). The Company provided continuous noise measurements over a 42 hour period for both locations (id. at 7-39 and 7-40). The Company stated that the minimum L90 levels occurred at night and were 32 dBA at location 1, and 29 dBA at location 2 (id. at 7-41).

The Company estimated that the proposed facility would result in a ten dBA increase above the nighttime L90 levels at both locations (id.).

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

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

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

ii. Analysis

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

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

In a past review in which a proponent calculated that nighttime L90 would increase by seven dBA to a level of 48 dBA, the Siting Council raised concerns about the calculated maximum noise increase of seven dBA, citing the possibility of abutter complaints.(163) NEA Decision, 16 DOMSC at 401-403. Here, the Company's noise analysis at the

primary site indicates that at two residential receptors, the Cady Brook Apartments to the east and H. Foote Road to the west, facility operation would result in nighttime L90 increases of ten dBA, which would be the largest such noise increase ever accepted by the Siting Board.

In previous reviews, the Siting Board has included the level of existing background noise as a factor in assessing whether expected noise increases from a proposed generating facility would be acceptable. Berkshire Power Decision, 4 DOMSB at 404-405; Enron Decision, 23 DOMSC at 210. In a recent review, in which the proponent calculated that nighttime L90 would increase by eight dBA to a level of 41 dBA, the Siting Board approved that increase citing an analysis which demonstrated that Ldn noise at all residential receptors would be well below the USEPA's 55-dBA guideline.(164) Berkshire Power Decision, 4 DOMSB at 398, 404. However, in an earlier case where existing background noise levels were high, and the proponent calculated impacts at residences that would be in excess of the USEPA Ldn guideline, the Siting Board cited high existing noise levels in limiting further increases in nighttime L90 noise from facility operation to five dBA.(165) 1993 BECo Decision, 1 DOMSB at 108-109, 114.

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

As indicated by the Company, the principal source of high background noise at receptor 1 is time varying, reflecting vehicle traffic along Route 169. In contrast, previous Siting Board reviews which considered high background noise levels, including the 1993 BECo Decision and the Enron Decision, involved settings having significant levels of industrial source noise. The Siting Board recognizes that the difference in background noise source -- time varying traffic noise versus industrial noise which typically is more constant -- may reduce the significance of L90 noise increases in the instant case, as compared to the cited previous cases where high background noise levels were present.(166)

While the primary site noise analysis is distinct from those in previous cases with high background noise, the Siting Board cannot agree that the Company's proposed L90 increases at residential receptors are insignificant. The record indicates that nighttime facility noise impacts at the most affected receptors would approach the MDEP ten-dBA limit during quieter portions of the noise pattern, and would be perceptible half of the time or more during nighttime hours.(167) Further, the Siting Board is concerned that at the Cady Brook Apartments, the existing noise environment, as reflected by an Ldn of 67.5 dBA, may already be a source of annoyance to residents. The Siting Board also notes that at the Cady Brook Apartments, the projected Ldn of the proposed facility would be 54.7 dBA, a level which, by itself, would just meet the USEPA guideline.

The record indicates that the Company has considered options that would further mitigate noise impacts from operation of the proposed facility. The additional mitigation proposed under Option 1 and Option 2 would reduce expected noise increases that:

(1) would be well above the three-dBA threshold for noticeable noise; (2) would approach the ten-dBA limit at residential receptors and property lines; and (3) would be larger than increases previously accepted by the Siting Board. The record demonstrates that the Company has identified a noise mitigation option that would hold L90 increases at the most affected residences to 7.5 dBA. The record further demonstrates that the noise reductions that could be achieved at receptor 1 and receptor 2 (residential receptors) to the east of the proposed facility would be significant, and would result in effective noise reduction benefits to these residential areas. However, the Company has not proposed to implement either option to further mitigate noise impacts from the proposed facility, citing cost and limited effectiveness.

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

The record indicates that the Company's baseline noise mitigation package would result in calculated L90 increases of ten dBA at residential locations. Option 1 would hold calculated L90 increases to 7.5 dBA, an increase that would be within the range of the seven to eight dBA increases accepted by the Siting Board as reasonable limits in past cases where the Siting Board had sought to minimize noise impacts consistent with minimizing cost.

The Siting Board notes that the incremental cost of Option 1, nearly $900,000, plus an efficiency penalty of a little over $100,000 would exceed the cost of incremental mitigation required in past reviews, which has ranged from $175,000 to $500,000. As an offsetting consideration, the Siting Board also notes that the proposed facility would be somewhat larger than other generating facilities reviewed previously that were held to L90 increases of seven to eight dBA. Even allowing for its larger size, on balance, Option 1 would involve higher costs to attain L90 limits that would be comparable to those in past cases. At the same time, the Siting Board notes that the maximum L90 increase under Option 1, 7.5 dBA, exceeds the maximum L90 increase of 5 dBA accepted in previous cases with high background noise.(168) As a mitigating factor, we have recognized above that the significance of L90 increases may be less if background conditions reflect time varying traffic sources rather than steady-state sources. On balance, however, Option 1 would involve accepting L90 increases that are at best comparable to those in past cases, and that are potentially less preferable when considered together with substantial exceedances of the USEPA Ldn noise guideline that exist in the area.

Considering cost and environmental impacts together, Option 1 would involve somewhat higher noise mitigation costs than past cases, but also accepts the potential for somewhat more significant noise impacts than in past cases based upon evidence of both L90 increases and exceedance of the USEPA residential guideline. Thus, the noise increases provided for under Option 1 represent an appropriate balance between minimizing environmental impacts consistent with minimizing cost.

The Company has argued that, due to the conservatism of noise guarantees provided by the facility's various equipment providers, and to the conservatism of its noise model, noise increases that were calculated for the proposed facility would be overstated by three dBA to as much as five to eight dBA, depending on distance and direction from the proposed site.

The Siting Board accepts the Company's argument that its calculated noise impacts are likely to be conservatively overstated based on their incorporation of vendor noise guarantees. Further, the Siting Board accepts the Company's estimate that vendor guarantees result in conservative overstatement of noise impacts by one to as much as three dBA, but notes that the Company's assertions as to the appropriate extent of adjustment appear to be more judgmental than the original calculations of predicted noise. See Dighton Power Decision, at 55; Silver City Decision, 3 DOMSB at 336; NEA Decision, 16 DOMSC at 403. The Siting Board also recognizes that the Company's calculated noise impacts are likely to be conservatively overstated based on omission of environmental factors that potentially reduce noise. However, given that such factors are time-varying and are therefore not consistently present, we note that their omission may be appropriate for purposes of assessing worst-case noise impacts.

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

Therefore, in order to capture for affected abutters the benefits of conservatism in calculated noise increases, as well as to limit noise increases from the proposed facility to levels that are consistent with Siting Board precedent, the Siting Board directs the Company to meet either of the following conditions: (1) the Company shall incorporate noise mitigation measures into its pre-construction facility design such that calculated L90 noise increases would not exceed 7.5 dBA at residential receptors; or (2) the Company shall incorporate noise mitigation measures in its proposed facility such that measured L90 noise increases at residential receptors would not exceed six dBA.(169) The Siting Board notes that for either approach, the Company must, for all receptors, prevent L90 noise levels from increasing beyond the levels provided for under its baseline mitigation package.

Further, prior to commencing construction, the Company shall inform the Siting Board as to which of the two compliance approaches it will follow. Should the Company elect to meet the 7.5 dBA calculated limit, it shall submit to the Siting Board confirmation that it plans to proceed with Option 1 or, if an alternative noise mitigation package is preferred by the Company, provide information concerning its final noise mitigation package, including (1) a description of each mitigation measure to be incorporated in the proposed facility, (2) results of noise modelling showing that calculated L90 increases at residential receptors would not exceed 7.5 dBA, and (3) detailed cost information including the cost of each identified noise mitigation measure, including allowance for any efficiency penalties, and the total cost of noise mitigation for the proposed facility.

Should the Company elect to meet the six-dBA measured limit, it shall develop a noise testing protocol, to be implemented during the first twelve months of commercial operation, to determine that noise from operation of the proposed facility does not result in actual L90 noise increases of greater than six dBA at any of the residential receptors. Such testing protocol should be consistent with others that have been developed for testing compliance with the MDEP standard, and should be conducted at, or as close as is practicable to, the receptor locations identified in the Company's filing.

The Siting Board notes that noise mitigation measures required in this case are based upon the evidentiary record as presented. In setting forth its directive with respect to noise mitigation, it is not the intention of the Siting Board to suggest that greater latitude would be afforded at quieter sites with respect to allowable noise increases. Rather, it is the intent of the Siting Board to continue to evaluate each site in the context of the facility being proposed to ensure that environmental impacts are minimized consistent with minimizing cost.

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

e. Traffic

i. Primary Site

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

185, 6-192 to 6-195). The Company presented separate estimates of delivery vehicle volumes during construction and operation of the proposed facilities (id.).

The Company indicated that the majority of construction(170) activity would occur between 7:30 a.m. and 4:00 p.m., Monday through Friday (Exh. MPP-0, at 6-184).(171) The Company estimated that the maximum number of construction workers employed at any one time at the site would be 208 (id.). The Company presented a comparison of expected peak-hour levels of service ("LOS")(172) with and without the proposed project for each of the three primary gateway intersections, Route 20 and Route 169, Worcester Street and Route 169, and Route 169 and Sherwood Lane (id. at 6-190; Exh. EFSB E-128, att. A). The Company stated that the existing peak commuting periods in the area of the primary site are 7:15 a.m. to 8:15 a.m., and 4:30 p.m. to 5:30 p.m. (Exh. MPP-0, at 6-186). The Company stated that in estimating the number of trips created by the proposed project, it assumed 1.1 workers per car, that 100 percent of the workers would arrive during the morning peak period, and that 50 percent of the workers would depart during the evening peak (id. at 6-184).(173) In addition to employee work trips, the Company indicated that there would be 20 delivery vehicle round trips per day during peak construction (id. at 6-186). The Company stated that it assumed deliveries would be distributed evenly over a 10-hour delivery day (id.). The Company further stated that the delivery of very large equipment would be scheduled for off-peak times and that the Company would coordinate such deliveries with local officials (id.). Based on its analyses, the Company stated there would be no change in LOS due to construction-related traffic (id. at 6-190).(174)

The Company further stated that once the facility is fully operational, 14 employees would be on site during the day shift, and three employees would be required for the evening shift (id. at 6-192). The Company concluded that its traffic analysis demonstrates negligible impacts to intersection conditions during peak hours when the facility is operational, and that no changes in LOS are anticipated (id. at 6-195; Exh. EFSB E-128, att. B).

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

operation (Tr. 5, at 9-12).(176)

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

(Exh. EFSB E-164, atts. A and B).

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

ii. Alternative Site

The Company asserted that construction and operation of the proposed facility at the alternative site also would have minimal impacts on local traffic conditions (Exh. MPP-0, at 7-42). In support of its assertion, the Company developed projections of trip generation and related traffic impacts, with and without the proposed facility at the alternative site, including separate estimates of construction-related traffic and facility operation traffic (id. at 7-49 to 7-50, 7-52, 7-60). The Company based these projections on the same assumptions used for the primary site, except that morning peak hours are estimated to be 7:30 to 8:30 a.m. (id.). The Company presented a comparison of expected peak-hour LOS for five primary intersections: Route 31 and Flint Road, Route 31 and Burlingame Road, Route 31 and Old Worcester Road, Flint Road and Burlingame Road, and the site drive and Burlingame Road (id. at 7-57, 7-62). The Company indicated that LOS would be degraded in only one area, from LOS C to LOS D, solely for turns from Burlingame Road onto Route 31 during construction (id. at 7-57).(179)

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

iii. Analysis

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

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

The Siting Board notes that the Company's LOS analysis and the additional record information with respect traffic and accident statistics for Route 20 between Sturbridge and Auburn address different aspects of the existing traffic situation in the area surrounding the proposed facility sites. The LOS analysis focuses on traffic delays at intersections, and indicates no notable problems either at present or with construction and operation of the proposed facility. The additional Route 20 traffic and accident statistics focus on safety issues not necessarily related to traffic delay, and indicate some cause for concern based on apparent high incidence of accidents and fatalities along Route 20, notably between Route 169 and Route 31.

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

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

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

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

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

f. Safety

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

i. Materials Handling and Storage

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

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

The Company provided TSCREEN modeling which demonstrated that ammonia concentrations from a spill at the proposed facility at either the primary or the alternative site would be under the Immediately Dangerous to Life or Health ("IDLH") threshold of 500 parts per million ("ppm") at the nearest fenceline, property line, or public road (Exh. EFSB E-122 (rev.); Tr. 5, at 42 to 47). The Company stated that worst-case ammonia concentrations would fall below the IDLH threshold at the identified receptors even given a catastrophic spill of a full tank of aqueous ammonia under unfavorable meteorological conditions (Exh. EFSB E-122 (rev.)). Specifically, the Company's modeling predicted that worst-case ammonia concentrations from the proposed facility at the primary site would be 486 ppm at the nearest fence line, 124 ppm at the nearest property line, and 71 ppm at the nearest public road (Exh. EFSB E-122). At the alternative site, the Company anticipated ammonia concentrations from the proposed facility of 466 ppm at the nearest fence line, 466 ppm at the nearest property line and 49 ppm at the nearest public road (id.).

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

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

ii. Fogging and Icing

The Company stated that it used five years of meteorological data and the Seasonal/Annual Cooling Tower Plume Impact ("SACTI") model(183) to determine the likely frequency and location of fogging and/or icing due to evaporative cooling for the proposed facility at both the primary and alternative sites (Exh. MPP-0, at 6-27, 7-6; MPP-14, att. 1, at 7; Tr. 5, at 31). The Company stated that, with respect to either site, its modeling of facility plume over a five-year period predicted that ground-level fogging and icing would be confined to the immediate vicinity of the cooling towers themselves (Exh. MPP-0, at 6-27, 7-7; MPP-14, att. 1, at 7).

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

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

iii. Analysis

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

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

The record demonstrates that fogging and icing associated with the evaporative cooling tower for the proposed facility at both the primary and alternative sites would be limited to the immediate vicinity of the facility at both the primary and alternative sites, and that the towers have been sited to minimize fogging and icing. However, the Siting Board also notes that the conservative SACTI model predicts the potential for limited fogging and icing on public roadways. To minimize the potential impacts of fogging and icing on public roadways, the Siting Board directs the Company to work with the Town and the MHD to monitor fogging and icing in the vicinity of the proposed facility and, as necessary, to establish a plan with the identified local and state officials to ensure that any safety concerns are addressed.

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

g. Electric and Magnetic Fields(185)

i. Primary Site

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

The Company also pursued, but ultimately rejected, a two-line interconnection plan, which would have involved interconnection with a second NEPSCo transmission on the same ROW, the U-173 line, at a later date ("two-line plan"). The Company added that under the two-line plan, it would have pursued the reconductoring of the U-173 line to assist in delivering the plant's output to the area transmission system by sharing approximately half the plant's output with the W-123 line (id.).(187)

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

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

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

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

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

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

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

The Company indicated that the operation of the proposed facility would decrease magnetic field levels on the south side of the 302/V-174 ROW known as the Eastern corridor and increase magnetic fields on the north side (id. at 64-66; Exh. MPP-16, atts. 4,5).(190) The Company further indicated that under a wide variety of operating conditions, magnetic field levels would not exceed 50 mG at the edge of ROW along the Eastern corridor (Exh. MPP-16, atts. 4,5).(191) The Company stated that NEPSCo would reconductor the V-174 transmission line, and added that it would ask NEPSCo to investigate the potential for reductions in EMF levels and the associated costs (Exh. EFSB RR-16).

ii. Alternative Site

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

The Company stated that it did not perform load flow simulations to determine the impact of plant operation at the alternative site (Exh. EFSB E-108). However, the Company further stated that interconnecting at the alternative site could decrease power flows presently incurred along the segment of 302 line extending easterly to a NEPSCo substation in the Town of Millbury from the plant's point of interconnection (Exh. EFSB E-160b). The Company indicated that power flowing westerly along the 302 line between the proposed facility's point of interconnect and the Carpenter Hill substation would not likely be reduced as a result of operation of the proposed facilities at the alternative site (id.). The Company presented magnetic field calculations along the Eastern corridor indicating that, under several scenarios, magnetic field levels at the ROW edges would be well under 50 mG (Exh. MPP-0, at 7-68 to 7-69).(193)

iii. Analysis

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

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

The Company indicated that the 115 kV transmission lines on the Southwestern corridor and the Eastern corridor would be reconductored by NEPSCo as part of the interconnection strategy. The need for such reconductoring presents the Company and NEPSCo with the opportunity to select physical designs capable of minimizing magnetic field impacts.

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

arrangements in jointly selecting the final design for reconductoring the W-123 and V-174 circuits.

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

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

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

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

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

h. Land Use

i. Primary Site

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

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

The Company stated that the preferred site is located in a mixed industrial, commercial and residential area with a number of industrial facilities abutting the site (Exh. MPP-0, at 6-143, 6-145). The Company described the contiguous land uses as utility easements and vacant land to the north and west,(194)

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

The Company stated that most of the residential and vacant land in the vicinity of the site is located along roadways outside of the immediate Route 169 corridor (Exhs. MPP-0, at 1-9; MPP-4, att. C). The Company stated that presently the closest residence is located 800 feet southeast of the proposed facility on Sherwood Lane; however, the Company explained that this residence is located on property to be acquired by the Company as part of the site (Exh. EFSB E-92). Therefore, post construction, the nearest occupied residences would be the Cady Brook Apartments, a 24 unit complex approximately 1,000 feet east of the facility footprint and a single family residence located next to the apartment complex (Exhs. EFSB E-99, EFSB E-154, EFSB E-175b; EFSB RR-9).

Further, the Company stated that the nearest residences to the site property line are located less than 300 feet to the east of the site (Exhs. EFSB E-92; EFSB E-175). The Company indicated that approximately 100-150 residences are located within one-half mile of the preferred site (Exhs. EFSB E-92; MPP-18 at 6-7).

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

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

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

The Company asserted that the proposed facility would not have an adverse impact on historical or archaeological properties (Exh. MPP-0, at 6-156; Tr. 4 at 36). The Company stated that staff of the Public Archaeological Laboratory, Inc. ("PAL") surveyed the preferred site and identified three historic period structures of potential interest on the site, and that therefore the Company would follow the recommendations set forth in the PAL avoidance plan necessary to preserve the identified historic structures (Exhs. MPP-0, at

6-151 to 6-152; EFSB RR-41; Tr. 4, at 137) . The Company stressed that none of these structures will be disturbed by the proposed project or the related utility interconnections (Exhs. MPP-0, at 6-151 to 6-152; EFSB E-158, rev. A).

ii. Alternative Site

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

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

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

The Company stated that the alternative site is located in the Charlton Agricultural zone, in which an electrical generation facility is not a permitted use (Exh. MPP-0, at 7-20). Therefore, the Company stated that the alternative site would require a change in zoning designation in order for the Millennium project to be built (id.). The Company explained that any rezoning petition that would be filed in the event the Company was to develop the alternative site, would involve a number of parcels in the area, such as the abandoned landfill and not just the proposed alternative site (Tr. 4, at 161 to 162). The Company asserted that in its experience, such a rezoning is feasible (Exh. EFSB S-15, rev. A). The Company asserted that even though the site is zoned agricultural, there is little or no active farming in the immediate vicinity (Exh. MPP-0, at 7.)

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

iii. Analysis

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

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

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

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

The Siting Board notes that: (1) the alternative site is located in a rural-residential area with the nearest off-site residence located 600 feet from the facility footprint, and other residences located along the abutting roads, Burlingame Road and Flint Road; (2) there is no industrial land use within a half mile of the alternative site footprint, and commercial uses within a mile are minimal, consisting of a nursery, a retail store and two offices; (3) scenic landscapes including an area designated as distinctive in the DEM Landscaping Inventory are proximate to the alternative site (see Section III.B.2.c, above); and (4) the alternative site is zoned for agricultural/residential use and would require a change in

zoning. The Company has asserted that the presence of an abandoned landfill and utility easements, along with the DPW garage, are indicators of comparable industrial use. The Siting Board notes that utility easements can exist in any district and are not in and of themselves indicative of an industrial area. Further, an abandoned landfill would be categorized as vacant land and in its present decommissioned state is not readily associated with industrial use, especially in terms of building scale and related impacts. The Siting Board is aware that it may be appropriate to locate a generating facility in an agricultural district with large amounts of undeveloped land. However, in this case, the specific site is: (1) located in a district whose overall characteristic is large lot residential use and vacant land; (2) the facility would be less than one eighth of a mile from the nearest residence; (3) the facility would be proximate to scenic landscapes; and (4) the site would have to be rezoned.(201) These factors combine to create an inferior site on which to locate a generating facility.

Accordingly, the Siting Board finds that the primary site would be preferable to the alternative site with respect to land use.

3. Cost

In this section, the Siting Board evaluates whether the Company has provided sufficient information on the costs of the proposed facility to allow the Siting Board to determine if an appropriate balance has been achieved between environmental impacts and costs. The Siting Board then compares the estimated costs of constructing and operating the proposed facilities at the primary and alternative sites.

The Company stated that the total cost of the proposed facilities at the primary site would be $204,725,000 in 2000 dollars (Tr. 10, at 23).(202) The Company stated that this cost estimate includes an estimate of the site specific and current information regarding: (1) construction costs; (2) electric transmission line and gas pipeline interconnect costs; (3) a contingency allowance; (4) site acquisition costs; (5) other costs, including NOx offset costs; and (6) financing and related costs, including development costs (id.; Exh. MPP-11, att. 2). The Company further stated that the total cost of the proposed facilities at the alternative site

would be $209,500,000, approximately $4.775 million greater than at the primary site (Tr. 10, at 23). The Company stated that the increased costs at the alternative site would be due primarily to increased land acquisition costs and wastewater discharge/water supply pipeline costs (id.). The Company noted that the operation and maintenance costs of the facility at the primary and alternative sites would be essentially identical (id. at 26). The Company asserted that the cost estimate was realistic for a facility of this size and design based on the price of the equipment and the Company's experience in similar projects (id. at 30; Exh. MPP-0, at 6-207).

The Company also identified the costs of several options to further minimize the environmental impacts associated with the proposed facility including use of dry cooling, additional noise mitigation technology and using gas as the exclusive fuel (Exhs. EFSB E-63; EFSB RR-19; EFSB RR-36; MPP-7, at 7-8). The Company estimated that the capital cost of a dry cooling tower or a wet/dry cooling system would exceed the capital cost of the proposed evaporative cooling tower by $8.4 million to $14.4 million and that output and efficiency also would decrease with a dry or wet/dry cooling system (Exh. EFSB E-63). As noted above in Section II.B.2.d, the Company indicated that noise mitigation technology to further reduce the noise impacts at the most affected residential noise receptors would cost: (1) an additional $900,000 to limit the noise increase over the L90 to 7-8 dBA, and (2) an additional $2,600,000 to limit the noise increase over the L90 to 5-6 dBA at the most affected residential receptors (Exh. EFSB RR-19). The Company also indicated that the cost of a firm 365 day gas contract with dedicated firm gas transportation service to use gas as the exclusive fuel would increase fuel costs by $60 to $200 million over the ten year term of the proposed fuel supply contract (Exh. MPP-7, at 7-8). However, the Company noted that the cost of NOx offsets and SO2 allowances would decrease by approximately $178,635 if gas were used exclusively (Exh. EFSB RR-36).

The record contains estimates of the overall costs of the proposed facility at the primary and alternative sites, as well as cost information for measures to further minimize environmental impacts at both sites. The Company has noted specific cost advantages of siting the proposed facility at the primary site.

Accordingly, the Siting Board finds that the Company has provided sufficient information on the costs of the proposed facility to allow the Siting Board to determine which site is preferable with respect to cost and whether an appropriate balance would be achieved among environmental impacts and cost.

With respect to comparison of the primary and alternative sites overall, the Company's analysis shows a total capital cost advantage of approximately $4.775 million for the primary site over the alternative site. The record demonstrates that the cost of operating the proposed facility at the primary site would be comparable to the alternative site. Consequently, the Siting Board finds that the primary site is preferable to the alternative site with respect to cost.

4. Conclusions

In this section, the Siting Board reviews the consistency of the proposed facility with

its overall review standard, which requires that the appropriate balance be achieved between environmental impacts and costs. Such balancing includes trade-offs among various environmental impacts as well as between these environmental impacts and costs.

a.. Conclusion on the Proposed Facility at the Primary Site

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

As discussed in Sections III.B.2, above, the Company has identified and considered the cost-effectiveness of further measures for mitigation of the estimated noise impacts of the proposed facility. In addition, as part of its consideration of noise mitigation that would require increasing the height of the main building and stack, the Company considered the relative trade-off between noise and increased visual impact.

The Siting Board finds that, with the implementation of proposed mitigation and conditions, the noise impacts of the proposed facility would be minimized, consistent with minimizing cost. Therefore, the Siting Board finds that, with the implementation of the above conditions and with the conditions set forth in Sections III.B.2 above, the environmental impacts of the proposed facility at the primary site would be minimized consistent with minimizing cost.

b. Comparison of the Primary and Alternative Sites

In Section III.B.2 above, the Siting Board has found that:

- the primary site would be comparable to the alternative site with respect to air quality;

- the primary site would be comparable to the alternative site with respect to water supply;

- the primary site would be comparable to the alternative site with respect to water-related discharges;

- the alternative site would be preferable to the primary site with respect to construction-related impacts to wetlands;

- the primary site would be comparable to the alternative site with respect to visual impacts;

- the primary site would be preferable to the alternative site with respect to noise;

- the primary site would be preferable to the alternative site with respect to traffic impacts;

- the primary site would be slightly preferable to the alternative site with respect to safety;

- the alternative site would be preferable to the primary site with respect to EMF impacts; and

- the primary site would be preferable to the alternative site with respect to land use.

Accordingly, on balance, the Siting Board finds that the environmental impacts of the proposed facility at the primary site are superior to those at the alternative site.

The Siting Board also has found, in Section III.B.3, above, that the primary site would be preferable to the alternative site with respect to cost. Accordingly, the Siting Board finds that the primary site is preferable to the alternative site with respect to

minimizing environmental impacts consistent with minimizing cost.

IV. DECISION

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

In Section II.A, above, the Siting Board has found that the Company has established need for the proposed project. Further, in Sections II.B and II.C, above, the Siting Board has found that the proposed project is superior to all alternative technologies reviewed with respect to providing a necessary energy supply with a minimum impact on the environment at the lowest possible cost, and that upon compliance with the listed conditions, USGen has established that its proposed project is reasonably likely to be a viable source of energy. In Sections III.A and III.B, above, the Siting Board has found that USGen has considered a reasonable range of practical facility siting alternatives, and that with implementation of the listed conditions relative to air quality, water supply, water-related discharges, construction-related impacts to wetlands, visual impacts, noise, traffic, and safety, the environmental impacts of the proposed facility at the primary site

would be minimized consistent with minimizing cost. Finally, in Section III.B, above, the Siting Board has found that the construction and operation of the proposed facility at the primary site is preferable to construction and operation of the proposed facility at the alternative site.

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

In Sections III.A and III.B, above, the Siting Board has reviewed various environmental impacts of the proposed facility in light of related regulatory or other programs of the Commonwealth, including programs relating to air quality, water supply, water-related discharges, wetlands protection, noise, rare and endangered species, agricultural land preservation, and historical preservation. As evidenced by the above discussions and analyses, the proposed facility will be generally consistent with identified requirements under all such programs. In addition, prior to construction the Company shall file with the Siting Board a signed copy of its certificate on its FEIR.

Accordingly, the Siting Board APPROVES the petition of U.S. Generating Company to construct a 360 MW bulk generating facility and ancillary facilities in Charlton, Massachusetts subject to the following conditions during construction and operation of the proposed facility:

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

(B) In order to ensure that the project is likely to be operated and maintained in a manner consistent with appropriate performance objectives, the Siting Board requires USGen to provide a signed O&M contract between USGen and USOSC or a comparable entity that contains provisions that would provide reasonable assurance that the project would perform as a low-cost, clean power producer.

(C) In order to allow the Siting Board to monitor developments affecting gas capacity into New England, which relates to USGen's expectations as to the reliability of its fuel supply strategy, the Siting Board requires USGen to provide periodic updates on the status of gas supply projects to increase gas capacity into New England.

(D) In order to mitigate CO2 emissions, the Siting Board requires USGen to provide CO2 offsets through a donation of $370,000, to be paid in five annual installments of $74,000 during the first five years of facility operation, to a cost-effective CO2 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 CO2 offset requirement would be a donation in the amount of $305,000 to a cost-effective CO2 offset program or programs to be selected upon consultation with Siting Board Staff.

(E) In order to minimize impacts to water resources, the Siting Board directs USGen to provide a copy of the MDEP approval of G.L. c. 21G permit, together with any attached conditions and a detailed explanation of how all conditions will be met.

(F) In order to minimize wetland impacts, the Siting Board directs USGen to provide a copy of the Conservation Permit from the NHESP with attached conditions and a detailed explanation of how all conditions will be met.

(G) In order to minimize visual impacts, the Siting Board directs the Company, consistent with the directives in Section III.B.2.c, to develop and implement an off-site shrub and tree plantings or window awnings plan. In this regard, the Company: (1) shall provide shrub and tree plantings or window awnings on private property, only with the permission of the property owner, and along public ways, only with the permission of the appropriate municipal officials; (2) shall provide written notice of this requirement to public officials in Charlton and to all affected property owners prior to the commencement of construction;

(3) may limit requests from local residents and town officials for mitigation measures to a specified period ending no less than six months after initial operation of the plant; (4) shall complete all such mitigation measures within one year after completion of construction, or if based on a request after commencement of construction, within one year after such request; and (5) shall be responsible for the reasonable maintenance or replacement plantings as necessary to ensure that health plantings become established. In addition, the Siting Board directs USGen to make available to affected Harrington Road residents the option of at least one strategically placed planting of 20 feet or more as may be practical and appropriate to the setting, in lieu of a row of several smaller plantings.

(H) In order to minimize noise impacts consistent with minimizing cost, the Siting Board requires the Company to meet either of the following conditions consistent with the directives in Section II.B.2.d, above: (1) the Company shall incorporate noise mitigation measures into its pre-construction facility design such that calculated L90 noise increases would not exceed 7.5 dBA at residential receptors; or (2) the Company shall incorporate noise mitigation measures in its proposed facility such that measured L90 noise increases at residential receptors would not exceed 6.0 dBA.

(I) In order to minimize traffic related impacts, the Siting Board requires USGen, in consultation with the Towns of Auburn, Oxford, Sturbridge, and Charlton, to develop and implement a traffic mitigation plan which includes scheduling of the delivery of fuel oil, materials, and equipment to avoid peak daily travel periods or route modifications or

other appropriate measures to minimize traffic-related impacts along likely access routes to the site including Route 20 and Route 169.

(J) In order to minimize the potential impacts of fogging and icing on public roadways, the Siting Board directs USGen to work with the Town of Charlton and the MHD to monitor fogging and icing in the vicinity of the proposed facility and, as necessary, to establish a plan with the identified local and state officials to ensure that any safety concerns are addressed.

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

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

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

Jolette A. Westbrook

Hearing Officer

Dated this 3rd day of November, 1997

Unanimously APPROVED by the Energy Facilities Siting Board at its meeting of November 3, 1997 by the members and designees present and voting. Voting for

approval of the Tentative Decision as amended: Janet Gail Besser, (Commissioner, Acting Chair EFSB/DPU); John D. Patrone (Commissioner, DPU); Sonia Hamel (for Trudy Coxe, Secretary, Executive Office of Environmental Affairs); Francis Cummings (for David

A. Tibbetts, Director, Department of Economic Development); Nancy Brockway (Public Member); and Joseph Faherty (Public Member).

Janet Gail Besser

Acting Chair

Dated this 4th day of November, 1997

Appeal as to matters of law from any final decision, order or ruling of the Siting Board may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the order of the Siting Board be modified or set aside in whole or in part.

Such petition for appeal shall be filed with the Siting Board within twenty days after the date of service of the decision, order or ruling of the Siting Board, or within such further time as the Siting Board may allow upon request filed prior to the expiration of the twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the clerk of said court. (Massachusetts General Laws, Chapter 25, Sec. 5; Chapter 164, Sec. 69P).

1. 1 An additional portion of the site extends to the west of the transmission line toward

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

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

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

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

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

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

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

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

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

10. 10 In Point of Pines Beach Association v. Energy Facilities Siting Board, the Court noted the Siting Board's statutory requirement to make an independent finding of Commonwealth need, a finding that could not be premised solely on the existence of signed and approved PPAs. 419 Mass. 281, 285-286 (1995) ("Point of Pines"). Referencing its decision in Point of Pines, the Court vacated a final decision of the Siting Board for this same reason in Attorney General v. Energy Facilities Siting Board, 419 Mass. 1003 (1995) (Attorney General).

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

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

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

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

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

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

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

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

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

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

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

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

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

24. 24 The Company assumed that all replacement measures consisting of actual physical equipment, including units that were reactivated prematurely, would remain in place even when the Millstone units come back in service (Tr. 1, at 45). The Company noted that

NEPOOL includes the reactivated units as of their scheduled reactivation dates starting in 2000 (Exh. MPP-0, at 2-11).

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

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

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

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

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

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

31. 31 In addition, as noted above, in order to demonstrate extreme variations in expected demand, the Company provided summer and winter need forecasts based on the 1996 CELT report high and low demand forecasts (Exh. MPP-0, at 2-5 to 2-6). The Company developed 18 summer need forecasts by adjusting the 1996 CELT report high and low case summer demand forecasts by each of the three DSM forecasts, and combining each of the resulting six summer adjusted forecasts with three supply forecasts (Exh. MPP-13, exh. 2.1-9 (rev. A)). Of these 18 summer need forecasts, each of (1) the nine forecasts based on the high case demand forecast, and (2) the three low case demand forecasts combined with low supply forecasts, demonstrates a need of at least 360 MW of capacity

in 2000. However, the six low case demand forecasts combined with the base case or high supply forecasts do not demonstrate a need for at least 360 MW until the 2006 to 2010 time frame (id.). In addition, the Company developed 18 winter need forecasts in the same manner. Of these 18 winter need forecasts, each of (1) the nine forecasts based on the high case demand forecast, and (2) the three low case demand forecasts combined with low supply forecasts, demonstrate a need of at least 360 MW of capacity in 2000. However, like the similarly developed summer forecasts, the six low case winter demand forecasts combined with the base case or high supply forecasts do not demonstrate a need for at least 360 MW until the 2006 to 2010 time frame (id.). The Siting Board notes that NEPOOL defines the CELT low-case demand forecast as having a 90 percent chance of being exceeded. See n.13, above.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

54. 54 The Company also ran the POWRSYM3 model assuming that only combustion turbine peaking capacity would be added to meet reliability requirements in both the Millennium-in and Millennium-out cases (Exh. MPP-39). The Company asserted that this comparison more realistically demonstrates the full displacement benefits associated with the Millennium Power project -- reductions of 66,500 tons of SO2, 17,300 tons of NOx, and 6.1 million tons of CO2 over the six-year period (id.; Tr. 9, at 29). However, the Company also noted that it was not aware of any new combustion turbines proposed for the New England region while several combined-cycle projects are proposed (Tr. 9, at 31). The Siting Board notes that the Company's original analysis includes more realistic

assumptions regarding capacity likely to be added to the region during the forecast period and therefore relies on the original analysis.

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

56. 56 We note that for several regional or worldwide air quality concerns, including ozone, acid rain, and climate change, statutory or other policy goals point to a need to avoid or substantially minimize regional or national emissions increases. The pollutants that relate to such concerns include SO2, NOx, and CO2. See, Berkshire Power Decision, 4 DOMSB at 302.

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

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

59. 59 In past cases before the Siting Board, proponents have commonly included a generic version of their proposed technology among the technologies examined as alternatives to the proposed project. Invariably, however, these generic units do not include the project-specific modifications of the proposed project and are, therefore, most unlikely to offer a superior technological alternative. Given such experience, and in the interest of a review which addresses credible alternatives to the proposed project, the Siting Board will in future cases review a generic version of the proposed technology only if the generic unit is superior to the proposed project in some respect.

60. 60 The Company stated it used scaling procedures detailed in the 1993 TAG

(Exh. MPP-0, at 3-2).

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

81. The Siting Board notes that, although the Company has submitted an air permit application that, if approved, would allow it to burn oil for a maximum of 30 days per year, the Company states that it expects to minimize its reliance on oil and estimates that the fuel recall provision will be invoked approximately 10 days per year, coincident with needle peak days. The Siting Board notes however, that under USGen's gas supply strategy incorporating a 30 day recall provision on behalf of USGenFS, the recall option lies squarely with USGenFS, and is not confined to weather related situations to trigger the recall. The Siting Board further addresses this issue in Section III.B.2.a, below.

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

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

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

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

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

the two main trunk lines currently move 800,000 Mcf/d (Exh. EFSB RR-8). The Company further asserted that locating a facility on a spur line raises even more significant reliability constraints in the event of a physical problem with the pipeline (id.; Exh. EFSB S-20).

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

88. 88 This factor included an evaluation of the shape of the parcel, along with any geographic feature that would prevent the placement of a facility away from one or more of the site boundaries (Exhs. EFSB S-9; EFSB S-22; Tr. 4, at 68-70). The Company indicated that it did not consider the abutting zoning, terrain, or absence of natural buffers such as vegetation as part of this category (Exh. EFSB S-9).

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

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

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

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

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

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

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

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

97. In this case the noise analysis shows that Receptor 6, H. Foote Road, has as high a noise impact as any of the receptors, a nighttime L90 increase of 10 dBA, yet it is not the closest receptor to the proposed facility (see Section III.B.2.d).

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

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

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

101. The MDEP has adopted the NAAQS limits as MAAQS.

102. The Company indicated that it will be required to obtain SO2 allowances each year equal to the actual number of tons of SO2 emitted to comply with Title IV Sulfur Dioxide Allowances and Monitoring regulations (Exh. MPP-4, att. 6, at 3-4; Tr. 9, at 24). The Company added that SO2 allowances would be available for purchase through the Chicago Mercantile Exchange (Tr. 9, at 24-25).

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

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

105. The Company indicated that it conducted screening-level modeling for all expected operating load conditions using the EPA SCREEN3 computer program (Exhs. MPP-4, att. 6, at 5-1; MPP-4, att. 6 (rev.) at 5-1). The Company stated that air pollutant concentrations were modeled at simple terrain locations (below stack height) and at complex terrain locations (terrain locations above plume height), and that intermediate terrain (terrain between stack top and plume height) was evaluated by comparing the SCREEN3 output for complex and simple terrain (id.). Results for the load conditions that produced the highest predicted concentrations were then compared to significant impact levels ("SILs") or ambient air quality standards/PSD increments (id.). Additional, more refined modeling techniques -- the EPA-recommended ISCST3 computer program (which incorporates hourly meteorological data) and the CTSCREEN complex terrain screening model -- were used to evaluate operating scenarios which resulted in predicted concentrations above SILs at the screening level (id. at 5-2). The Company indicated that for those scenarios where screening-level modeling resulted in emissions at above-SILs concentrations, refined analyses using the ISCST3 and CTSCREEN models showed that impacts of the proposed facility on ambient concentrations of criteria pollutants would be below SILs (id. at 5-14 to 5-20).

106. Scaling was performed for each air toxic by dividing the SO2 concentration by the SO2 emission rate and then multiplying by the emission rate for each air toxic (Exh. MPP-4, att. 3, at 7-20).

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

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

109. The Company stated that since the identified metals would not be expected to volatilize from the cooling tower, it did not anticipate that the metals would be included

in the water vapor plume in appreciable quantities (Exhs. EFSB E-25; MPP-4, att. 6, at 4-11 to 4-12). The Company stated that VOCs found in the cooling tower make-up water might be emitted, but that most VOCs would be volatilized in the wastewater treatment process at the Southbridge WWTP (Exhs. EFSB E-25; MPP-4, att. 6, at 4-10 to 4-11). The Company therefore anticipated that concentrations of VOCs, and thus their rate of emission from the cooling tower, would be insignificant (Exhs. EFSB E-25; MPP-4, att. 6, at 4-11; MPP-4, att. 6 (rev.) at 4-3).

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

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

112. The Siting Board notes that an offset of one percent of annual facility CO2 emissions of 1,234,810 tons, at $1.50 per ton equals $18,510 per year or $370,200 for twenty years. The Company stated that the proposed donation, in 2000 dollars, is based on the equivalent donation accepted in the Dighton Power Decision, scaled to reflect the larger size of the proposed Millennium facility, and is a rounded net present value of the identified twenty-year amount, plus a significant premium to account for future price fluctuations (Exh. EFSB E-40 (supp. C)).

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

114. Previously, the Siting Board required developers to commit to a specific program of CO2 mitigation, such as a tree planting or forestation program, designed to offset a certain percentage of emissions within the early years of facility operation. See Berkshire Power Decision, 4 DOMSB at 373-374.

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

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

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

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

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

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

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

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

123. The four river flow conditions are: (1) the average summer flow; (2) the extreme low flow -- the seven day average low flow which has a probability of occurring once in ten years ("7Q10"); (3) the two-year peak flow; and (4) the five-year peak flow (Exhs. MPP-0, at 6-63, 6-102; EFSB E-77).

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

125. The Company stated that the various operating scenarios caused water quality changes under 7Q10 and average summer flow conditions (Exh. MPP-4, att. 3, at 12-67). The Company stated that the worst case scenario would be 7Q10 flow and low WWTP makeup water conditions (id. at 12-67 to 12-72). However, the Company noted that

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

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

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

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

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

130. The Company noted that an average daily discharge flow in excess of 1.0 mgd would not be essential under any operating or maintenance condition and that a greater discharge flow, beneficial under certain conditions such as maintenance outages, would

not be discharged unless it was acceptable to the Southbridge WWTP (Exh. EFSB E-73c).

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

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

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

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

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

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

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

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

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

140. The Company stated that, because the Town of Charlton does not own sufficient property in the vicinity to allow for wetland replication, the Company has developed an

on-site wetland replication plan which will be submitted to the Charlton Conservation Commission for approval (Exh. EFSB V-47 (supp. B)-A at 3-7).

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

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

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

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

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

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

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

148. The Company stated that classification of the area relative to the Massachusetts Landscape Inventory was not specifically taken into account in the site selection process

but that overall visual impacts of the proposed facility at primary and alternative sites was a criteria used in the selection of the primary site over the alternative site (Tr. 8, at 100).

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

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

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

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

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

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

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

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

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

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

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

160. The Siting Board notes that under Option 1, the actual decrease in facility noise at the various receptors shows some variation around the nominal three dBA reduction proposed under this option. Combined facility and background noise (L90) at receptor 6 would be decreased by 3.3 dBA while noise at receptors 1 and 2 would be decreased by 2.3 dBA and 1.9 dBA respectively.

161. The Siting Board notes that under Option 2, the actual decrease in facility noise at the various receptors would be somewhat less than the nominal six dBA reduction proposed under this option. Combined facility and background noise impacts (L90) at receptor 6 would be decreased by 4.3 dBA while noise impacts at receptors 1 and 2 would be decreased by 4.3 dBA and 3.0 dBA respectively.

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

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

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

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

166. A time varying pattern of background noise may result in calculation of a higher L90 noise increase, as this measure reflects the quietest ten percent of the pattern. Also, importantly, a time varying noise environment results in higher masking of facility noise impacts during the noisier portion of the pattern.

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

168. The record demonstrates that limiting facility noise to a calculated L90 increase of 5 dBA would require the implementation of Option 2, with an incremental cost of approximately $2,600,000, plus efficiency costs of approximately $430,000.

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

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

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

172. Regarding its peak-hour traffic comparison, the Company indicated that the efficiency of traffic operations at a location is measured in terms of LOS (Exh. MPP-0, at 6-178). The Company further indicated that LOS is measured in terms of traffic flow along roadways and intersections and is described in terms of Levels A through F, where

A represents the best possible conditions and F represents forced-flow or failing conditions (id. at 6-178, 6-180).

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

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

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

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

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

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

179. The Company stated that even at this intersection, overall intersection delay at the study area intersection is maintained at LOS A, operating well within acceptable parameters (Exh. MPP-0, at 7-55). Further, the Company indicated that the temporary change in LOS during construction would result in only short delays averaging 21

seconds instead of average delays of 11 seconds expected without the addition of construction traffic (id.).

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

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

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

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

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

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

186. The Siting Board notes that NEPSCo's and other utilities' existing transmission lines are not ancillary facilities as defined in G.L. c. 164, § 69G. However, in order to allow comprehensive analysis of environmental impacts associated with the construction and operation of the proposed generating facility at both sites, the Siting Board may identify and evaluate any potentially significant effects of the facility on magnetic field levels

along existing transmission lines. See Berkshire Decision, 4 DOMSB at 417; Altresco Lynn Decision, 2 DOMSB at 213; 1993 BECo Decision, 1 DOMSB at 148, 192.

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

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

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

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

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

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

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

193. The Company stated that no reconductoring or other changes to existing facilities along the Eastern corridor are required as a result of operation of the proposed facilities at the alternative site (Exh. EFSB E-113). As such, the Company stated that there would be no opportunity to lower magnetic fields at little additional cost (id.). However, the Company added that by interconnecting at 345 kV, the current flow on the interconnect

line and on the 302 circuit is lower than for a 115 kV interconnection, and therefore no further design options have been considered (id.).

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

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

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

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

198. The Company indicated that in addition to a nursery, the specific commercial uses consisted of one retail store/commercial warehouse, an engineering office, and an

in-home business (Exh. EFSB E-105, att. A).

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

200. In the Silver City Decision, the Siting Board did find that an abutter property guarantee program was warranted to establish that land use impacts would be adequately minimized. Id. 3 DOMSB at 365.

201. 201 Consistent with Siting Board precedent, the fact that rezoning would be required does not in and of itself make the site unsuitable for development. NEA Decision, 16 DOMSC at 392.

202. The Company estimated that new design modifications to the electrical interconnect will reduce costs by $8 million to $10 million at the primary site (Exh. EFSB RR-40 (supp. A)).