COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Board

In the Matter of the Petition of Silver City Energy Limited Partnership to Construct a Bulk Generating Facility and Ancillary Facilities	)	EFSB 91-100

FINAL DECISION

Jolette Westbrook
Hearing Officer
June 15, 1994

On the Decision:

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LIST OF ABBREVIATIONS

Abbreviation	Explanation
AAL	Annual Allowable Ambient Limits
active primary site	The approximately 25-acre site on the TMLP property leased to SCE for development of the proposed TEC
Algonquin	Algonquin Gas Transmission Company
Altresco-Pittsfield Decision	Altresco-Pittsfield, Inc., 17 DOMSC 351 (1988)
Altresco-Lynn Decision	Altresco-Lynn, Inc., 2 DOMSB 1 (1994)
Attorney General	Attorney General of the Commonwealth of Massachusetts
Attorney General Brief	Initial Brief filed by the Attorney General in EFSB 91-100 (Brief dated 7/29/92)
Attorney General Reply Brief	Reply brief filed by the Attorney General in EFSB 91-100 (Brief dated 8/12/92)
Attorney General Supplemental Brief	Initial Brief filed by the Attorney General in the reopened proceedings of 91-100 (Brief filed 3/15/93)
Attorney General Supplemental Reply Brief	Reply Brief filed by the Attorney General in the reopened proceedings of 91-100 (Brief filed 3/23/93)
BACT	Best Available Control Technology
Bay State	Bay State Gas Company
Bechtel	Bechtel Group, Incorporated
BCI	Bechtel Construction, Inc.
Board of Appeals	Taunton Zoning Board of Appeals

Abbreviation	Explanation
BPC	Bechtel Power Company
Btu/kWh	British thermal unit per kilowatt hour
CAA	Federal Clean Air Act
Cabot Power Decision	Cabot Power Corporation, 2 DOMSB 241 (1994)
CAGR	Constant Annual Growth Rate
CAGR Forecast	Regional Forecast based on CAGR regression trend
CEI	Constellation Energy Inc.
CELT Report	NEPOOL Capacity, Energy, Load and Transmission Report
C&LM	Conservation and load management
CFB	Circulating Fluidized Bed
CFC	Coal Facts Committee
cfs	Cubic feet per second
CGCC alternative	Coal Gasification Combined-Cycle Unit
City of New Bedford	City of New Bedford v. Energy Facilities Siting Council, 413 Mass. 482 (1992).
Cleary Substation	Cleary Flood electric generating station
CLF	Conservation Law Foundation
CLF Brief	Initial Brief filed by CLF in EFSB 91-100 (Brief dated 7/29/92)

Abbreviation	Explanation
CLF Reply Brief	Reply Brief filed by CLF in EFSB 91-100 (Brief dated 8/12/92)
CO	Carbon Monoxide
CO_2	Carbon Dioxide
Company	Silver City Energy Limited Partnership
Condominiums	Cranes Landing Condonminium complex
Conference Report	Joint Explanatory Statement of the Committee of Conference, Federal Energy Guidelines, FERC Statutes & Regulations, Vol. I, at 5106
COSI	Constellation Operating Services Inc.
CSC	Cogeneration Services Corporation
CTCC	Combined Cycle Combustion Turbine
Cyprus	Cyprus Emerald coal mine (Pennsylvania)
dBA	Decibels
DCRs	Debt coverage ratios
Department	Department of Public Utilities
Destec	Destec Energy, Inc.
DO	Dissolved Oxygen
DSM	Demand Side Management
EEC Decision	Eastern Energy Corporation, 22 DOMSC 188 (1991)
EEC Compliance Decision	Eastern Energy Corporation, 25 DOMSC 296 (1992)

Abbreviation	Explanation
EEC (Remand) Decision	Eastern Energy Corporation (on Remand), 1 DOMSB 213 (1993)
EFSB 90-100R Tr 28	Transcript 28 from the proceedings in EFSB 90-100R
Elaborate Multiple Regression	An analysis prepared by the Attorney General based on up to six independent variables for each class
EM Forum	1988 Energy Modeling Forum
Enron	Enron Power Enterprise Corporation
Enron Decision	Enron Power Enterprise Corporation, 23 DOMSC 1 (1991)
EOER	Massachusetts Executive Office of Energy Resources
EPA	United States Environmental Protection Agency
EPC	Engineering, procurement and construction
EPRI	Electric Power Research Institute
EUA	Eastern Utilities Associates
EMF	Electric Magnetic Fields
Expected Value Forecast	The expected value forecast prepared by NEPOOL and presented in its 1992 Resource Assessment
FERC	Federal Energy Regulatory Commission
GNP	Gross National Product
GNP Forecast	Regional Forecast based on GNP

Abbreviation	Explanation
GNP-IPD	Gross National Product implicit price deflator
GEP	Good engineering practice
gpd	Gallons per day
gpm	Gallons per minute
GOCC alternative	A natural gas/oil-fired combined cycle unit with interruptible gas supply and a distillate oil back-up
Graban Brief	Initial Brief filed by William Graban in EFSB 91-100 (Brief dated 7/29/92)
Graban Reply Brief	Reply Brief filed by William Graban in EFSB 91-100 (Brief Dated 8/12/92)
Graban Supplemental Brief	Supplemental Initial Brief filed by William Graban in the reopened proceedings of EFSB 91-100 (Brief dated 3/15/93)
GTF	NEPOOL Generation Task Force
gwh	Gigawatt hours
HMM	HMM Associates, Inc.
H_2S	Hydrogen Sulfide
IDLH	Immediately Dangerous to Life and Health -- toxicity thresholds
IPP	Independent Power Producer
IRM	Integrated Resource Management
IRR	International rate of return
ISCST	Industrial Source Complex Short-Term air model
kWh	Kilowatt Hour

Abbreviation	Explanation
kV	Kilovolt
Ldn	maximum day-night noise level
L_{90}	dBA level that is exceeded 90 percentof the time
lbs/MMBtu	Pounds per million Btu
LGTI	Louisiana Gasification Technology, Inc.
Linear Regression Forecast	Regional Forecast based on 1974-1990 linear regression trend
LOS	Level of Service
Martin Project	Proposed 1600 MW coal gasification project in Martin County, Florida
Massachusetts Expected Value Forecast	CAGR projection of peak loads for the years 1992-2007 based on the Massachusetts reference forecast
Massachusetts End Year CAGR Forecast	CAGR projection of peak loads for the years 1992 to 2007 based on the NEPOOL-forecasted 2007 peak load in the Massachusetts reference forecast
Massachusetts linear Regression Forecast	Forecast based on the projection of the 1974-1991 linear regression trend over the 1992-2007 forecast period
Massachusetts Reference Forecast	The NEPOOL 1992-2007 energy and peak load forecast for Massachusetts
Massachusetts CAGR Regression Forecast	Forecast based on the projection of the 1974-1991 CAGR regression trend over the 1992-2007 forecast period
MassPIRG	Massachusetts Public Interest Research Group

Abbreviation	Explanation
MASSPOWER Decision	MASSPOWER, Inc., 20 DOMSC 301 (1990)
MASS ReLeaf	Massachusetts ReLeaf tree-planting program
MCZM	Massachusetts Coastal Zone Management
MDEM	Massachusetts Department of Environmental Management
MDEP	Massachusetts Department of Environmental Protection
MEOTC	Massachusetts Executive Office of Transportation and Construction
mG	milligauss
MGD	Million gallons per day
mg/l	Milligrams per liter
MRI	Marine Research, Inc.
MVA	Megavolt-amperes
MVARS	Megavolt-amperes-reactive
MW	Megawatt
NAAQS	National Ambient Air Quality Standards
NEA	Northeast Energy Associates
NEA Decision	Northeast Energy Associates, 16 DOMSC 335 (1987)
Need Contingency Cases	Massachusetts need cases based on (1) adjusting the base supply forecast to reflect each of the Company's nine contingencies which would increase or decrease supply, and (2) comparing

Abbreviation	Explanation
	those nine adjusted supply forecasts with the demand forecasts
NEDC	Northeast Environmental Defense Council
NEES	New England Electric System
NEPOOL	New England Power Pool
NESCAUM	Northeast States for Coordinated Air Use Management
net-of-displacement emissions	increments of emissions exceeding the emmissions of displaced capacity
NGCC alternative	A natural gas-fired, combined cycle unit with firm, (i.e., 365 day), gas supply
NGW Fuel Forecast	Fuel price forecast based on projected 1992 through 1994 spot market gas prices quoted in "Natural Gas Week"
NO-COAL	Greater New Bedford NO-COALition
NOx	Nitrogen Oxides
NPDES	National Pollutant Discharge Elimination System
NPV	Net present value
NSPS	New Source Performance Standards
NU	Northeast Utilities
NUG	Non-Utility Generator
O_3	Ozone
O&M	Operation and maintenance costs
OP4	NEPOOL Sequential operating procedures

Abbreviation	Explanation
PASNY	Power Authority of the State of New York
PC alternative	Pulverized Coal-fired power plant
PG&E	Pacific Gas and Electric Company
PG&E/Bechtel	PG&E/Bechtel Generating Company
PM-10	Particulate matter
PPAs	Power Purchase Agreements
PPM	Parts per million
PSD	Prevention of Significant Deterioration
PURPA	Public Utility Regulatory Policy Act of 1978
QF	Qualifying [cogeneration or small power producer] Facility
R^2	Percentage of explained variation
Reference forecast	Regional Forecast based on the 1992 CELT Report reference case forecast
REMVEC	Rhode Island - Eastern Massachusetts - Vermont energy control alea
Reorganization Act	Chapter 141 of the Acts of 1992
RFP	Requests for proposals
Resource Assessment	1992 NEPOOL Resource Adequacy Assessment
RO alternative	Residual oil-fired power plant
ROW	Right-of-Way
R.W. Beck	R.W. Beck and Associates
SCE	Silver City Energy Limited Partnership

Abbreviation	Explanation
SCE Brief	Initial Brief filed by SCE in EFSB 91-100 (Brief dated 7/29/92)
SCE Fuel Forecast	Forecast of future fuel prices based on 1992 delivered prices adjusted by 1992 GTF fuel-specific escalation rates
SCE Reply Brief	Reply Brief filed by SCE in EFSB 91-100 (Brief dated 8/12/92)
SCE Supplemental Brief	Supplemental Brief filed by SCE in the reopened proceedings of EFSB 91-100 (Brief dated 3/15/93)
SCE Supplemental Reply Brief	Supplemental Reply Brief filed by SCE in the reopened proceedings of EFSB 91-100 (Brief dated 3/23/93)
SCR	Selective catalytic reduction
Siting Board	Energy Facilities Siting Board
Siting Council	Energy Facilities Siting Council
Siting Council IRM Decision	Rulemaking Regarding the Procedures by Which Additional Resources are Planned, Solicited, and Procured by Investor-Owned Electric Companies (Integrated Resource Management), Final Order On Rulemaking, 21 DOMSC 91 (1990).
SJC	Supreme Judicial Court
SO_2	Sulfur Dioxide
SNCR	Selective non-catalytic reduction
TAG	EPRI Technical Assessment Guide
TEC	Taunton Energy Center
TEL	Threshold Effects Exposure Limits

Abbreviation	Explanation
Third Report	Third Report of the Massachusetts Electric Power Plant Siting Commission, House No. 6190, March, 1973
TMLP	Taunton Municipal Lighting Plant
TMLP Brief	Initial Brief filed by TMLP in EFSB 91-100 (Brief dated 7/29/92)
TMLP Property	The approximate 100 acre site in Taunton, Massachusetts on which the TMLP complex is located
TMLP Reply Brief	Reply Brief filed by TMLP in EFSB 91-100 (Brief dated 8/12/92)
TMLP tap lines	115kV transmission lines from the Cleary Substation
TPY	Tons Per year
TSP	Total suspended particles
USGS	United States Geological Survey
VOC	Volatile Organic Compounds
Wabash	Wabash River Coal Gasification Repowering Project
West Lynn	West Lynn Cogeneration, Inc.
West Lynn Decision	West Lynn Cogeneration, 22 DOMSC 1 (1991)
Whittenton Substation	TMLP's Whittenton Junction Substation
WPA	Wetlands Protection Act

Abbreviation	Explanation
1989 TAG	Technical Assessment Guide issued by EPRI, dated September 1989
1993 BECo Decision	Boston Edison Company, 1 DOMSB 1 (1993)
1992 BECo Decision	Boston Edison Company, 24 DOMSC 125 (1992)
1985 BECo Decision	Boston Edison Company, 13 DOMSC 63 (1985)
1991 Berkshire Decision	Berkshire Gas Company, 23 DOMSC 294 (1991)
1990 Berkshire Decision	Berkshire Gas Company (Phase II), 20 DOMSC 109 (1990)
1992 CELT Report	NEPOOL Forecast Report of Capacity, Energy, Loads and Transmission, 1992-2007
1991 CELT Report	NEPOOL Forecast Report of Capacity, Energy, Loads and Transmission, 1991-2006
1990 CELT Report	NEPOOL Forecast Report of Capacity, Energy, Loads and Transmission, 1990-2005
1985 MECo/NEP Decision	Massachusetts Electric Company/New England Power Company, 13 DOMSC 119 (1985)
$/Mwh	Dollars per megawatt hour

The Energy Facilities Siting Board ("Siting Board") hereby APPROVES subject to conditions the petition of Silver City Energy Limited Partnership to construct a 169 megawatt bulk generating facility and ancillary facilities at the primary site in Taunton, Massachusetts.

I. INTRODUCTION

A. Summary of the Proposed Project and Facilities

Silver City Energy Limited Partnership ("SCE" or "Company") has proposed to construct a coal-fired electric generating facility with a nominal electrical output of 150 megawatts ("MW"), the Taunton Energy Center ("TEC"), in the City of Taunton, Massachusetts.[1] The proposed project would be located on an approximately 25-acre site located within an approximately 100-acre parcel of land of the Taunton Municipal Lighting Plant ("TMLP") complex (Exhs. SCE-1, at 1-1; SCE-3, at II.1-1).[2]

The proposed TEC includes the following major components and structures: (1) a boiler building housing a single reheat type circulating fluidized bed ("CFB") boiler providing steam to a single turbine-generator; (2) an exhaust gas baghouse; (3) lime and ash storage silos; (4) an emission stack approximately 397 feet in height; (5) a turbine generator building; (6) an administrative and warehouse building; (7) an enclosed coal storage building and coal crusher building; (8) a coal unloading building and train break-down yard; (9) a cooling tower; (10) storage tanks for condensate, wastewater, and ammonia; (11) a wastewater treatment plant; and (11) a CO_2 production plant (Exhs. SCE-1, at 1-1, 1-2;

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1 The proposed facility is designated and capable of producing a gross output of 169 MW (Exh. SCE-3, at III.1-5). Approximately 19 MW would be used within the plant to power blowers, pumps, etc. (id.). Therefore, the nominal (net) electrical output of the TEC would be approximately 150 MW (id.).

2 The 100-acre parcel of land is irregularly shaped and is roughly bounded by the Taunton River to the east; parcels on Railroad Avenue to the south; parcels on Somerset Avenue (Route 138) to the west; and the existing TMLP access road to the north (Exh. SCE-3, at III.2-1). The existing TMLP Cleary Flood electric generating station ("Cleary Substation"), which produces approximately 137 MW of power for the City of Taunton is located in the northeast quadrant of this 100-acre parcel (id.). The proposed site of the TEC, which is located to the south and west of the existing TMLP, is bisected by a railroad siding running north to south that will be rehabilitated to provide rail access to the site (id.).

SCE-3, at III.1-4, 1-5, 1-6, 1-14, 1-18). Further, SCE stated that new overhead transmission lines would have to be constructed to connect the proposed facility to the existing TMLP switchyard, where two existing transmission lines originate that connect to the regional 115 kilovolt ("kV") transmission system (Exhs. SCE-3, at III.1-23; EFSC-E-71).

The proposed facility would be primarily fueled by eastern bituminous coal with natural gas to be used for start-up and stabilizing combustion (Exh. SCE-3, at III.1-1, 1-2). The fuel for the TEC would be transported to Taunton by rail along an existing rail right-of-way ("ROW") in unit trains, each 80 rail cars in length, and containing 8,000 tons of coal (id. at III.1-2). From Taunton, the coal trains would be delivered to the TEC via an upgraded 3.1-mile industrial rail siding (id.). The resultant ash from the proposed facility would be removed from the site for disposal via the same rail system (id. at II.1-7). Limestone, which would be used to control SO_2 emissions from the CFB, would be purchased in pulverized form and delivered in eight 25-ton trucks per day, five days per week (Exh. EFSB-AER-10). A thirty-day supply of coal and five-day supply of limestone would be stored on the site in enclosed buildings (Exh. SCE-3, at III.1-4, 1-6).

The wastewater treatment facility of the TEC would process an average of 38.5 gallons per minute ("gpm") (id. at III.1-22). Of this amount, 30 gpm would be used in the ash pelletizing plant and the remaining 8.5 gpm of treated wastewater would be discharged to the Taunton River via the existing TMLP discharge pipe (id.). The source of the cooling tower make-up water would be from the Taunton River via the existing Cleary Substation intake (id. at II.1-16). City water, which would be used for boiler makeup water, other miscellaneous uses, and fire protection water, would be provided to the TEC from an existing water main (id. at III.1-19).

As proposed, the TEC would operate as a cogenerator, supplying steam to a proposed CO_2 production plant to be constructed on the facility site (Exh. SCE-1, at 1-1).[3] As such,

[3] For a discussion regarding the CO_2 plant, see Section II.C, below.

SCE stated that the proposed facility would be a qualifying facility ("QF") under the Public Utility Regulatory Policies Act of 1978 ("PURPA") (id.).[4]

The proposed project is being developed by SCE which is a limited partnership comprised of affiliates of Constellation Energy, Inc. ("CEI"), an energy development affiliate of Baltimore Gas and Electric Company; PG&E/Bechtel Generating Company ("PG&E/Bechtel"), a partnership between PG&E Enterprises, a non-utility subsidiary of Pacific Gas and Electric Company ("PG&E"), and Bechtel Enterprises Corporation, a subsidiary of Bechtel Group, Incorporated ("Bechtel"); and Cogeneration Services Corporation ("CSC") (id. at 1-1, 2-1 through 2-11). SCE stated that although this is the first energy project developed by SCE: (1) CEI is part-owner in twenty-four energy projects that are either in operation or under construction, and is currently participating in the development of over twenty additional power projects; (2) PG&E/Bechtel combines the diverse experience and resources of PG&E, the largest combined gas and electric investor-owned utility in the nation, and Bechtel, the leading engineering and construction company to the electric utility industry; and (3) CSC is a full-service company supporting the cogeneration industry with extensive experience in management, engineering, and operational and regulatory requirements for cogeneration facilities (id.). As project developer, SCE is responsible for all of the development activities, which include licensing and permitting, arranging project financing, overseeing construction and operations, and fuel procurement (id. at 1-1). Bechtel Power Company ("BPC"), an affiliate of Bechtel, will provide engineering and construction services to the proposed project and Constellation Operating Services Inc. ("COSI"), a subsidiary of CEI, an experienced operator of CFB boilers will operate the facility (id.). The Company stated that construction could be completed in approximately three years and that the capital cost of the proposed facility at the primary site would be approximately $200 million.

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[4] PURPA requires electric utility companies to purchase power from QFs for a price at or below the utilities' avoided cost of production. See, 16 U.S.C. §§ 796, 824a-3. The Company has submitted to the Federal Energy Regulatory Commission ("FERC") a notice of self-certification to certify the TEC as a QF under PURPA (Exhs. SCE-1, at 1-1; EFSC-B-4; EFSC-B-4S).

B. Jurisdiction

SCE's petition to construct a bulk generating facility and ancillary facilities is filed in accordance with G.L. c. 164, §§ 69H and 69J. G.L. c. 164, § 69H requires the Siting Board to ensure a necessary energy supply for the Commonwealth with minimum impact on the environment at the lowest possible cost. Further, G.L. c. 164, § 69J, 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 cogeneration facility with a nominal output of 150 MW, SCE's proposed generating unit falls 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 of more.

At the same time, SCE's proposals to construct transmission lines and other structures at the site falls 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 February 15, 1991, SCE filed a petition with the Energy Facilities Siting Council ("Siting Council")[5] for approval to construct a coal-fired generating facility with a nominal

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[5] Pursuant to Chapter 141 of the Acts of 1992 ("Reorganization Act"), the Siting Council was merged with the Department of Public Utilities ("Department") effective September 1, 1992. Reorganization Act, § 55. Petitions for approval to construct facilities that were pending before the Siting Council prior to September 1, 1992 were to be decided by the newly created Siting Board which is within, but not under the control or supervision of, the Department. Id., §§ 9, 15, 43, 46. The terms Siting Council and Siting Board will be used throughout this Decision as appropriate to the (continued…)

output of 150 MW and ancillary facilities in the City of Taunton, Massachusetts. On May 2, 1991, SCE submitted an amended petition.[6] The Siting Council docketed this case as EFSC 91-100. On June 27, 1991, the Siting Council conducted a public hearing in Taunton, Massachusetts. In accordance with the direction of the Hearing Officers, SCE provided notice of public hearing and adjudication.

Petitions to intervene were filed by: (1) TMLP; (2) Conservation Law Foundation Inc. ("CLF"); (3) Massachusetts Public Interest Research Group ("MassPIRG"); (4) William Graban, individually, and on behalf of COAL-FACTS Committee ("CFC"); and (5) Fran J. Perry. In addition, the Office of the Attorney General ("Attorney General") filed a notice of intervention in this proceeding pursuant to 980 C.M.R. § 1.05(2)(f) and G.L. c. 164, § 69L. Petitions to participate as an interested person were filed by the Town of Norton, Greater New Bedford NO-COALition ("NO-COAL"), Northeast Environmental Defense Council ("NEDC"), Mrs. Edward McDonald, Joseph and Audrey Zrebiec, and Dorothy Latour.

On October 15, 1991, the Hearing Officers conducted a pre-hearing conference to address intervention issues and to establish a discovery schedule. At that conference, the petitions to intervene of the Attorney General, TMLP, CLF, Mr. Graban, as an individual,[7]

(…continued)
circumstances being discussed.

The Reorganization Act provides that all facility petitions before the Siting Board, regardless of when they were filed, will be reviewed consistent with all orders, rules and regulations duly made, all approvals duly granted, and all legal and decisional precedents established by the Siting Council until superseded, revised, rescinded, or cancelled in accordance with law by the Siting Board. Id., § 46.

6 The amendment described a project design change that incorporated a single 150 MW reheat type CFB boiler in place of two 75 MW non-reheat type CFB boilers.

7 Even though Mr. Graban and CFC petitioned together as intervenors, the Hearing Officers granted status to Mr. Graban to intervene as a party and status to intervene as an interested person to CFC noting that CFC and Mr. Graban are essentially the same and can, therefore, be adequately represented by Mr. Graban. The Hearing Officers (continued…)

and Fran Perry were allowed. In addition, the petitions to participate as an interested person of the Town of Norton, NO-COAL, NEDC, Mrs. McDonald, Joseph and Audrey Zrebiec, and Ms. Latour were allowed. On October 18, 1991, the Hearing Officers issued a procedural order allowing MassPIRG's intervention.

Initially, the Siting Council conducted 19 days of evidentiary hearings commencing on December 12, 1991 and ending on April 2, 1992. SCE presented 14 witnesses: Dale T. Raczynski, an environmental consultant with HMM Associates, Inc. ("HMM"), who testified regarding environmental review and permitting issues relative to the project; Robert V. Bibbo, an environmental consultant with HMM, who testified regarding the air quality modeling and assessment portion of the project; Kenneth P. Roberts, a consultant with CSC who served as project manager for the proposed TEC, who testified regarding project construction, financing, operation, viability, need, noise, carbon dioxide ("CO_2") emissions, and fuel transportation; Samuel G. Mygatt, a project director for HMM, who testified regarding environmental review and permitting issues relative to the project; Bruce E. Fishman, from ICF Kaiser Engineers, who testified regarding air toxic evaluations; Richard C. Toner, President of Marine Research, Inc., who testified regarding the impacts of the facility on the Taunton River; Boyd Montgomery, Vice President of Business Development with CEI, who testified regarding financing, fuel procurement, ash disposal and transportation strategies of the project; Arshad Nawaz, a project engineer with BPC, who testified regarding design and construction of the facility; David N. Keast, an acoustical consultant, who testified regarding noise impacts of the facility; Peter Thalmann, who testified regarding electrical interconnection issues; John J. Reed, President of Reed Consulting Group, who testified regarding New England Power Pool ("NEPOOL") planning issues, and the Capacity, Energy, Load and Transmission Report ("CELT"); Sandra L. Ringelstetter, an engineer with R. W. Beck and Associates ("R. W.

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also noted that unincorporated groups need to be clearly defined in terms of membership, purpose and interest in the proceeding (Pre-Hearing Conference, October 15, 1991, Tr. at 6 through 7).

Beck"), who testified regarding NEPOOL's probabilistic assessment; Theodore F. Kuhn, an economist with R. W. Beck, who testified regarding the load forecasts used in the analysis of power supply; and James A. Booth, an engineer with R. W. Beck, who testified regarding need for the project and cost comparison of the project to alternate approaches. The Attorney General presented one witness, Donald M. Shakow, an economist who testified regarding the analysis of need for the project and load forecasting methodologies presented by SCE.

On April 24, 1992, the Hearing Officers suspended the established briefing schedule, and on May 1, 1992, the Hearing Officers reopened the record in this proceeding for the limited purpose of incorporating information contained in the CELT Report for the years 1992-2007 ("1992 Celt Report") and, accordingly, established a limited discovery schedule. On July 1, 1992, and July 2, 1992, additional evidentiary hearings were held on the issues relative to the 1992 CELT Report.

On July 29, 1992, pursuant to a schedule established by the Hearing Officers, initial briefs were filed by SCE ("SCE Brief"), TMLP ("TMLP Brief"), CLF ("CLF Brief"), William Graban ("Graban Brief") and the Attorney General ("Attorney General Brief"). On August 12, 1992, reply briefs were filed by SCE ("SCE Reply Brief"), TMLP ("TMLP Reply Brief"), CLF ("CLF Reply Brief"), William Graban ("Graban Reply Brief"), and the Attorney General ("Attorney General Reply Brief").

On September 11, 1992, SCE filed a motion to reopen the record in the present proceeding to include evidence necessary to comply with the decision of the Supreme Judicial Court ("SJC") in City of New Bedford v. Energy Facilities Siting Council, 413 Mass. 482 (1992) ("City of New Bedford"). In City of New Bedford, the SJC remanded the conditional approval of a proposed generating facility to the Siting Council "to compare alternative energy resources" in its review of that proposed generating facility.[8] Id. at 484. The Company

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[8] In City of New Bedford, the SJC also identified four other issues that might arise on remand:

> (1) Because the Siting Council's mandate referred to a necessary energy supply for the Commonwealth, the Siting Council's finding that additional energy

(continued…)

contended that based on the SJC's decision, it is clear that the parties did not have an opportunity to compare this project to other alternative resources, including alternative fuel technologies (SCE September 11, 1992 Motion at 3). Further, the Company contended that if its motion to reopen was not granted, parties would not have an opportunity to address an issue specifically excluded by the Siting Council during the course of the proceeding (id.).[9] In addition, the Company stated that since the SJC did not give the Siting Board guidance as to the methodology to be used for establishing regional need, the parties in the present case should be given an opportunity to file testimony on the issue of how the proposed facility provides a necessary energy supply for the Commonwealth (id.).

The Attorney General and CLF filed replies to the motion to reopen on September 16, 1992, and September 22, 1992, respectively. In his reply to the motion, the Attorney General urged the Siting Board to defer ruling on the motion until the Siting Board decides whether SCE proved that New England needs the proposed facility (Attorney General Reply at 1). The Attorney General argued that if in all of New England there is not a need for the proposed facility, then it follows logically that there is not a need for the proposed facility in

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(…continued)

resources are needed for New England was inadequate (413 Mass. at 489);
(2) The Siting Council must make a finding that the proposed project would produce power at the lowest possible cost (Id.);
(3) The Siting Council must determine that the proposed project would provide a "necessary" energy supply (Id. at 489-490); and
(4) The final decision must be "accompanied by a statement of reasons … including determination of each issue of fact or law necessary to the decision …" (Id. at 490).

9 On November 1, 1991, The Attorney General filed a motion in limine for determination as to the relevance and admissibility of evidence comparing fuel technologies. In denying the Attorney General's motion in limine, the Hearing Officers stated that in the Siting Council's most recent review of projects proposed by non-utility developers, the Siting Council rejected the approach of comparing an applicant's proposed project with generic alternative generation or fuel technologies with respect to cost, environmental impact, reliability, and ability to meet the identified need, to determine whether a proposed project is superior to alternative approaches (Pre-Hearing Conference, November 15, 1991, Tr. at 4).

Massachusetts alone (id. at 2). CLF endorsed the position of the Attorney General (CLF Reply at 1).

On October 19, 1992, the Hearing Officers issued a Procedural Order granting SCE's motion to reopen the record in this proceeding.[10] In that Order, the Hearing Officers found that SCE had sufficiently demonstrated why the submission of evidence regarding a comparison of alternative energy resources and the need for the proposed facility in the Commonwealth is relevant to this proceeding. To comply with the SJC's directive in City of New Bedford, the Hearing Officers reopened the proceedings to allow evidence into the record regarding (1) a comparison of alternative fuel technologies, and (2) whether the proposed facility is needed in the Commonwealth (Hearing Officer's Procedural Order, October 19, 1992, at 6).

In the reopened proceeding, the Siting Board conducted 16 days of evidentiary hearings commencing on December 18, 1992 and ending on February 17, 1993. SCE presented one additional witness who had not testified in any of the earlier hearings: Richard La Capra, a utility analyst and principal of La Capra Associates, who testified regarding financial aspects of alternative technologies and the need for the proposed facility.

The Attorney General presented three additional witnesses who had not testified in the earlier hearings: Paul Horowitz, an independent public policy consultant specializing in energy resource planning and related issues, who testified regarding demand side management ("DSM") issues; Kenneth M. Keating, an evaluation consultant for the Bonneville Power Administration, who testified regarding DSM evaluations; and David L. Breton, a manager of

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10 In the Order granting the motion to reopen, the Hearing Officers stated that in City of New Bedford, the SJC presented new evidentiary issues that must be addressed to meet the Siting Board's statutory mandate in cases such as the instant one. In recognizing that such evidentiary issues would not have been addressed by the Siting Council under its previous standard of review, the Hearing Officers determined that SCE's motion satisfied the regulatory requirement under 980 C.M.R. § 1.05(12) that evidence SCE was seeking to introduce was unavailable at the time of hearing (Hearing Officer's Procedural Order, October 19, 1992, at n.7).

process systems engineering for Destec Energy, Inc. ("Destec"), who testified regarding coal gasification.

On March 15, 1993, pursuant to a schedule established by the Hearing Officers, supplemental initial briefs were filed by SCE ("SCE Supplemental Brief"), William Graban ("Graban Supplemental Brief"), and the Attorney General ("Attorney General Supplemental Brief"). On March 23, 1993, supplemental reply briefs were filed by SCE ("SCE Supplemental Reply Brief") and the Attorney General ("Attorney General Supplemental Reply Brief"). During the course of the entire case, the Hearing Officers entered 585 exhibits into the record, consisting primarily of information and record request responses.[11] In addition, SCE entered 323 exhibits into the record; the Attorney General entered 255 exhibits into the record; William Graban entered 49 exhibits into the record; MassPIRG entered 54 exhibits into the record; and CLF entered 11 exhibits into the record. On June 2, 1994, TMLP filed a notice of withdrawal as a party, and thus, is no longer a party to this proceeding,

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 four phases. First, the Siting Board requires the applicant to show that additional energy resources are needed. Cabot Power Corporation, 2 DOMSB 241, 253 ("1994") ("Cabot Power Decision"); Altresco Lynn, Inc., 2 DOMSB 1, 17 ("1994") ("Altresco Lynn Decision"); Eastern Energy Corporation (on Remand), 1 DOMSB 213, 421 (1993) ("EEC (remand) Decision"); Northeast Energy Associates, 16 DOMSC 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

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11 In addition, the Hearing Officer took Administrative Notice of the following: (1) IRM Rulemaking, D.P.U. 89-239 (1990); (2) 220 C.M.R. § 8.00; and (3) EEC (remand) Decision, 1 DOMSB 213, Transcript 28, at 28-12 through 28-36 ("EFSB 90-100R Tr.28"), including all documentation and exhibits referred to in those pages of the transcript.

identified need and in terms of cost, environmental impact, and reliability.[12] Cabot Power Decision, 2 DOMSB at 253; Altresco Lynn Decision, 2 DOMSB at 17; EEC (remand) Decision, 1 DOMSB at 296; NEA Decision, 16 DOMSC at 364 (see Section III.B, below). Third, the Siting Board requires the applicant to show that its project is viable. Cabot Power Decision, 2 DOMSB at 253; Altresco Lynn Decision, 2 DOMSB at 18; Boston Edison Company (Phase II), 1 DOMSB 1, 23 (1993) ("1993 BECo Decision"); NEA Decision, 16 DOMSC at 364 (see Section II.C, below). Finally, the Siting Board requires the applicant to show that its site selection process did not overlook or eliminate clearly superior sites, and that the proposed site for the facility is superior to the alternative site in terms of cost, environmental impact, and reliability of supply. Cabot Power Decision, 2 DOMSB at 253; Altresco Lynn Decision, 2 DOMSB at 18; 1993 BECo Decision, 1 DOMSB at 23; EEC Decision, 22 DOMSC 188, 315-316 (1991); NEA Decision, 16 DOMSC at 343 (see Section III.B, below).

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12 In City of New Bedford, supra, the SJC stated that this standard of review, which was applied by the Siting Council up to 1990, comports with its statutory mandate. 413 Mass. at 485. Subsequent to the SJC's ruling, the parties in the present proceeding were invited to address in their briefs the precise standard of review that should be applied here.

II. ANALYSIS OF THE PROPOSED PROJECT

A. Need Analysis

1. Standard of Review

a. Positions of the Parties

i. The Company's Position

The Company stated that in previous cases involving facility applications by non-utility generators, the Siting Council has consistently determined that there is a need for a proposed facility if the applicant has demonstrated that the new capacity to be provided by the proposed facility will satisfy projected load and reserve requirements over-and-above projected levels of capacity (SCE Supplemental Brief at 7). SCE stated that in City of New Bedford, the SJC criticized the Siting Council's analysis only because the finding related to New England rather than the Commonwealth (id. at 7 through 8). Further, SCE stated that there is nothing in either the statute or the SJC's decision that requires the Siting Board to use a certain methodology to evaluate whether the proposed facility is needed (id. at 8).

The Company argued that, consistent with the statutory mandate and the SJC's decision in City of New Bedford, the are two reasonable approaches for the Siting Board to use to determine whether the proposed facility is needed based on reliability considerations -- a demonstration of a capacity deficiency for Massachusetts or a demonstration of a capacity deficiency on a regional basis (id. at 8 through 9). The Company stated that, where a capacity deficiency is demonstrated for Massachusetts based on a reasonable methodology, the clear language of the statute requires a finding that the proposed facility is needed to provide a necessary energy supply for the Commonwealth (id. at 8).

In the alternative, the Company asserted that the Siting Board can find need for a proposed facility where deficiency is demonstrated on a regional basis, provided that the analysis determines and explains the reasons why a finding of regional need meets the statutory requirements (id. at 9). SCE stated that given the tangible benefits to Massachusetts resulting from participation in the NEPOOL system, it is consistent with the Siting Board's statute to base need for the proposed facility on regional considerations (id. at 12-13).[13,14]

In addition, the Company stated that, although the SJC was silent on the appropriateness of using economic efficiency[15] as an independent basis of determining need, the economic-efficiency analysis is consistent with the Siting Board's obligation to ensure a necessary energy supply at the lowest possible cost and with a minimum impact on the environment (id. at 13). Accordingly, the Company argued, if an applicant can demonstrate

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[13] SCE asserted that participation in NEPOOL offers Massachusetts consumers significant benefits such as: (1) NEPOOL facilitates economic dispatch of generating units which minimizes electricity costs for Massachusetts utilities and consumers; (2) NEPOOL's existence allows for lower reserve margins, which, in turn, lowers costs and the potential environmental impact of the electricity generation that would otherwise be required; and (3) NEPOOL produces benefits associated with a diversity of suppliers, diversity of fuel sources, and flexibility with maintenance scheduling which greatly increases reliability and decreases costs for Massachusetts (SCE Supplemental Brief at 12).

[14] The Company noted that the legislative history of the original enabling statute is set forth in the Third Report of the Massachusetts Electric Power Plant Siting Commission ("Third Report") (SCE Supplemental Brief at 9). Further, the Company asserted that the Third Report is replete with references to NEPOOL and confirms that the Legislature recognized the importance of Massachusetts' utilities' participation in NEPOOL and the inextricable link between regional and Massachusetts reliability (id.).

[15] The Company noted that in Enron Power Enterprise, 23 DOMSC 1 (1991) ("Enron Decision") the Siting Council found that economic efficiency can establish need if the addition of the proposed new facility would result in lower generation costs for the system than would be experienced without the new facility (SCE Supplemental Brief at 13).

The Siting Board notes that in the Enron Decision, the Siting Council found that the facility was needed for economic efficiency purposes in addition to reliability purposes. 23 DOMSC at 63-65. The Siting Council made it clear that it would have to evaluate, on a case-by-case basis, whether the magnitude and timing of the economic efficiency gains identified would be adequate to establish need solely on economic efficiency grounds. Id., 23 DOMSC at 59-60. See also, Altresco Lynn Decision, 2 DOMSB at 65-68.

that a proposed facility will result in lower costs for the Commonwealth, that should be sufficient to establish need.

The Company argued that in assessing need for future capacity addition, the Siting Board should not review only the first year in which a project is scheduled to begin operation since small or isolated surpluses or deficiencies in an individual year need to be viewed in a long-term planning context to determine the optimal mix of resources (SCE Supplemental Reply Brief at 4).[16]

ii. The Attorney General's Position

The Attorney General argued that the criteria for showing Massachusetts need must reconcile the language of G.L. c. 64 § 69H and the SJC's decision in City of New Bedford, with the integrated nature of the Massachusetts and regional electricity system through participation in NEPOOL (Attorney General Supplemental Brief at 8 through 9). The Attorney General also argued that where a non-utility generator proposes to build a power plant in Massachusetts but has not yet sold most of its power, the Siting Board should begin its determination of need with an analysis of regional capacity (id. at 8). Further, the Attorney General argued that a demonstration of regional capacity surplus should compel a finding that the proposed facility was not needed while demonstration of a regional deficiency would require a further showing of reliability benefits to the Massachusetts electricity system (id. at 7 through 8). In addition, the Attorney General argued that the Siting Board has consistently held that reliability benefits to Massachusetts may be shown only through the existence of signed and approved sales contracts with Massachusetts utilities (id. at 13). The Attorney General also noted that the Siting Board should adhere to its consistent precedent of (1)

16 The Company argued that in previous decisions, the Siting Council approved projects that were not likely to be needed in the first year of operation (SCE Supplemental Reply Brief at 4). For example, the Company stated that in determining need in the Enron Decision, the Siting Council considered a two-year window following the first year of commercial operation (id.).

planning to a confidence level of 50 percent; and (2) evaluating the need for a non-utility project based on the first year in which that project will be on-line (id. at 14).

b. Analysis

In the EEC (remand) Decision, the Siting Board set forth a standard of review for the analysis of need for non-utility developers consistent with the statutory mandate to implement the energy policies to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost and the SJC's directive in City of New Bedford.

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

With respect to the issue of regional need vs. Massachusetts need, in the EEC (remand) Decision, 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. The Siting Board noted the inherent reliability and economic benefits which flow to Massachusetts as a result of this integration. Thus, the Siting Board concluded that consideration of regional need must be a central part of any need analysis for a power generation project not yet linked to individual utilities by power purchase agreements ("PPA's"). See, EEC (remand) Decision, 1 DOMSB 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 has found that an analysis of regional need must form the foundation for an analysis of Massachusetts need. Id. at 417.

SCE argued that a showing of either a Massachusetts capacity deficiency or a regional capacity deficiency should be sufficient, on its own, to establish need for a proposed facility. As stated above, however, the Siting Board has recognized in past reviews that a regional capacity analysis provides a necessary foundation for, rather than the sole determinant of, a finding of need.[17] Id. at 419; Cabot Power Decision, 2 DOMSB at 257; Altresco Lynn Decision, 2 DOMSB at 24. Therefore, neither a regional capacity deficiency, taken alone, nor a Massachusetts capacity deficiency, taken alone, would be sufficient to establish need. Id.

Finally, with respect to the issue of establishing need on economic efficiency grounds, the Siting Board agrees with the Company that such analyses of need would be consistent with our statutory obligation to ensure a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. G.L. c. 164, §§ 69H, 69J. The Siting Board has found that a demonstration of Massachusetts need based on reliability, economic efficiency or other benefits associated with additional energy resources from a proposed project remains a necessary element of a need review. Cabot Power Decision, 2 DOMSB at 317-319; Altresco Lynn Decision, 2 DOMSB at 65-68; EEC (remand) Decision, 1 DOMSB at 417-418. However, in response to the SJC's reminder in City of New Bedford that our statutory mandate is limited to ensuring that a necessary energy supply is provided for the Commonwealth, the Siting Board found in the EEC (remand) Decision that reliability, economic, or environmental benefits associated with the additional energy resources from a

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[17] The Siting Board has also found that determination of a regional capacity surplus would be insufficient by itself to establish that a proposed facility was not necessary for the Commonwealth's energy supply. See, EEC (remand) Decision, 1 DOMSB at 419. The Siting Board noted that an applicant could establish that reliance on a regional surplus to address or offset a Massachusetts supply deficiency could involve transmission or other reliability constraints or could be contrary to the statutory mandate to ensure that a necessary energy supply is provided for the Commonwealth at the lowest possible cost with the least environmental impact. Id.

proposed project must directly relate to the energy supply of the Commonwealth to be considered in support of a finding of Massachusetts need. 1 DOMSB at 418.

After considering the arguments presented by the Company and the Attorney General, the Siting Board finds that the standard of review for the determination of need established in the EEC (remand) Decision continues to be appropriate. The standard is set forth below.

c. Conclusion

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 evaluating the need for new energy resources to meet reliability objectives, the Siting Board may evaluate the reliability of supply systems in the event of changes in demand or supply, or in the event of certain contingencies. With respect to changes in demand or supply, the Siting Board has found that new capacity is needed where projected future capacity available to a system is found to be inadequate to satisfy projected load and reserve requirements. Cabot Power Decision, 2 DOMSB at 254; Altresco Lynn Decision, 2 DOMSB at 26; EEC (remand) Decision, 1 DOMSB at 421-422; New England Electric System, 2 DOMSC 1, 9 (1977). With regard to contingencies, the Siting Board has found that new capacity is needed to ensure that service to firm customers can be maintained in the event that a reasonably likely contingency occurs. Middleborough Gas and Electric Department, 17 DOMSC 197, 216-219 (1988); Boston Edison Company, 13 DOMSC 63, 70-73 (1985) ("1985 BECo Decision"); Eastern Utilities Associates, 1 DOMSC 312, 316-318 (1977). The Siting Board also may determine under specific circumstances that additional energy resources are needed primarily for economic or environmental purposes related to the Commonwealth's energy supply. Cabot Power Decision, 2 DOMSB at 258; Altresco Lynn Decision, 2 DOMSB at 26; EEC (remand) Decision, 1 DOMSB at 422.

While 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,[18] but also the consideration of whether proposals to construct energy facilities within the Commonwealth are needed to meet New England's energy needs. Cabot Power Decision, 2 DOMSB at 258-259; Altresco Lynn Decision, 2 DOMSB at 27; EEC (remand) Decision, 1 DOMSB at 422; Massachusetts Electric Company/New England Power Company, 13 DOMSC 119, 129-131, 133, 138, 141 (1985) (1985 MECo/NEP 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 NEPOOL.

Thus, in cases where a non-utility developer seeks to construct a jurisdictional generating facility principally for a specific utility purchaser or purchasers, the Siting Board requires 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 Inc. 17 DOMSC 351, 366-367 (1988) ("Altresco-Pittsfield Decision"). 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

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18 See, Hingham Municipal Lighting Plant, 14 DOMSC 7, 14-18 (1985); 1985 BECo Decision, 13 DOMSC at 70-73.

or environmental grounds directly related to the energy supply of the Commonwealth. Cabot Power Decision, 2 DOMSB at 259; Altresco Lynn Decision, 2 DOMSB at 27; EEC (remand) Decision, 1 DOMSB at 423; West Lynn Cogeneration, 22 DOMSC 1, 9-47 (1991) ("West Lynn Decision").

2. Power Sales

In the NEA Decision, the Siting Council found that, consistent with current energy policies of the Commonwealth, Massachusetts benefits economically from the addition of cost effective QF resources to its utilities' supply mix. 16 DOMSC at 358. In that case, the Siting Council 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 of the need for additional energy resources for reliability purposes. Id.

Here, SCE and TMLP have signed a PPA for 30 MW of capacity from the proposed project, but the contract has not been approved. Further, the record provides no indication that any of the remaining project output has been sold.

Accordingly, based on the foregoing, the Siting Board finds that SCE has not established that its proposed project is needed for economic efficiency or reliability reasons in Massachusetts through signed and approved PPAs. Therefore, the Siting Board reviews the Company's analyses of regional and Massachusetts need to determine whether the proposed project is needed to provide a necessary energy supply for the Commonwealth.

3. New England's Need

a. Introduction

SCE asserted that there is a need for 150 MW in New England beginning in the time frame 1996 to 2000 and beyond (SCE Brief at 14, 17, 66). In support, the Company: (1) presented a series of forecasts of demand and supply for the region, based, in part, on data and forecasts published by NEPOOL; (2) combined its demand and supply forecasts to produce a series of need forecasts; and (3) subjected its need forecasts to a variety of contingency tests to evaluate the sensitivity of the need projections to the uncertainty inherent in the underlying forecast assumptions (Exhs. SCE-1, Section 4; SCE-9; SCE-11, at 1-11, attached exhibits 1 through 11A; EFSC-N-48; EFSC-N-62).[19] SCE asserted that it provided a comprehensive and reliable assessment of the need for the capacity of the proposed facility on reliability grounds, consistent with Siting Council standards (SCE Brief at 17, 65-66, 71 through 72).

SCE also presented an analysis of regional need based on economic efficiency grounds (Exhs. SCE-9; EFSC-RR-120). The Company asserted that its analysis establishes that the proposed project would provide significant and assured economic efficiency benefits, and together with the analysis of regional reliability need, conclusively demonstrates that the proposed project will be needed on either reliability or economic efficiency grounds (SCE Brief at 74, 93).

In the following sections, the Siting Board reviews the demand forecasts provided by the Company, including the demand forecast methodologies and estimates of DSM savings over the forecast period, and the supply forecasts provided by the Company, including the capacity assumptions and required reserve margin assumptions. The Siting Board then reviews the need forecasts, which are based on a comparison of the various demand and supply forecasts. Finally, the Siting Board reviews the Company's analysis of economic efficiency based need.

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19 SCE originally provided an analysis of regional need based, in part, on load forecast data contained in the NEPOOL CELT Report 1990-2005 ("1990 CELT Report") and the CELT report 1991-2006 ("1991 CELT Report") (Exhs. SCE-1, sec. 4; SCE-9; EFSC-RR-126). In May 1992, the Company updated its analysis of regional need to include load forecast data from the 1992 CELT Report 1992-2007 (Exh. EFSC-N-62).

b. Demand Forecasts

The Company indicated that it developed demand forecasts based on four different demand forecast methodologies for adjusted peak load[20] (Exh. SCE-9, at 9). The Company also modified results from each of the four initial, or base, demand forecasts to provide additional demand forecasts reflecting higher and lower projections of future reductions in peak load resulting from utility-sponsored DSM programs (id. at 10; Exh. SCE-1, at 4-20).[21] Thus, the Company presented 12 demand forecasts of adjusted peak load demand, including alternative DSM levels (Exhs. EFSC-N-48, attachment; EFSC-N-62).

i. Description

The Company stated that it developed its demand forecasts based on the following four methodologies: (1) the 1992 CELT Report reference case forecast for the period 1992-2006 ("reference forecast");[22] (2) a regression forecast over the period 1991-2006 based on the 1974-1990 relationship between peak load and Gross National Product ("GNP") and

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[20] Adjusted peak load refers to the peak electrical load that must be supplied, after reflecting actual or expected reductions from DSM.

[21] SCE referred to the identified higher and lower DSM projections as "alternative futures," and considered such alternatives as part of a sensitivity analysis that also included supply contingencies (Exh. SCE-1, at 4-18 through 4-26).

[22] The Company also provided forecast analyses based on the 1990 and 1991 CELT Report forecasts (see n.19, above). The Siting Board notes that the Company described the 1990 CELT Report forecast as reliable, but considers it to be a low case (SCE Brief at 22). We further note that the Attorney General recommended use of the 1991 CELT Report forecast as the best basis to forecast need (see Section II.A.3.b.2, below). However, these forecasts are now three and four years old. Further, in previous reviews of electric generating facilities, the Siting Council has found that the 1991 CELT Report forecast -- the more recent of the two forecasts -- is unreliable and should not be used to determine regional need. See, Enron Power Enterprises Corporation, 23 DOMSC 1, 43 (1993) ("Enron Decision"). We also note that both the Company and the Attorney General discussed in detail possible adjustments to the reference forecast that correct for methological or other differences from earlier CELT Report forecasts, including differences that are of central concern to such parties. Accordingly, the Siting Board does not further consider the 1990 and 1991 CELT report forecasts of unadjusted peak load in this review.

assumed future GNP growth rates ("GNP forecast"); (3) a historical time series regression forecast over the period 1991-2006, based on projection of the 1974-1990 constant annual growth rate ("CAGR") regression trend ("CAGR regression forecast"); and (4) a historical time series regression forecast over the period 1991-2006, based on projection of the 1974-1990 linear regression trend ("linear regression forecast") (Exhs. SCE-9, at 6-8, exhibit 2).

The Company indicated that one of its four forecast methodologies -- the reference forecast -- was developed on a common basis in both the regional need analysis and the Massachusetts need analysis (Exh. EFSB-RR-168).[23]

To develop the reference forecast, the Company explained that NEPOOL produced (1) a short-term forecast for the years 1992 and 1993 based on an econometric model, and (2) a long-term forecast for the years 1992 through 2007 based on an end-use model (Exh. N-63R at 1 through 2). NEPOOL used the long-term forecast results for the years 1996 and beyond, but merged the short-term and long-term forecast results to produce projections for the years 1994 and 1995 (id.).[24]

SCE stated that NEPOOL also produced two alternative forecasts of future regional peak demand as part of the 1992 CELT report -- a high demand forecast and a low demand forecast -- which are based on different sets of economic assumptions (id.).[25] SCE indicated

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23 The Company used two of its reference case forecasts -- its base reference forecast and high DSM reference forecast -- to assess the relative timing of need in the regional need analysis, as compared to that in the Massachusetts need analysis (Exh. EFSB-RR-168) (see section II.A.4, below). The Siting Board notes that, although the CAGR regression forecast and linear regression forecast methodologies were also used in both the regional and Massachusetts need analyses, the results are not comparable because the Massachusetts regression analyses were based on one additional year of historical data.

24 Mr. Reed stated that NEPOOL did not specify how the short-term and long-term model results were merged (Tr. 24, at 92 through 93).

25 The Company stated that the low forecast is extraordinarily pessimistic, reflecting an unprecedented decline in demand, while the high forecast is optimistic, assuming a robust economic recovery similar to those experienced over the last 20 years (Exh.

(continued...)

that NEPOOL uses the high demand forecast and the low demand forecast as a bandwidth around the reference case, and characterizes: (1) the high demand forecast as having a 10 percent probability of being exceeded; and (2) the low demand forecast as having a 90 percent chance of being exceeded (SCE Brief at 43, citing, Exh. EFSC-N-61b; Tr. 24 at 101). SCE further indicated that NEPOOL also prepared the 1992 Resource Adequacy Assessment ("Resource Assessment"), which provides probabilistic analyses of the demand forecast, DSM program impacts and future supply resource availability (id. at 48 through 49, citing, Exh. SCE-RR-6).[26]

SCE stated that it regards the reference forecast as a reasonable projection of peak load in the long run (Exh. EFSB-MN-2b; Tr. 24, at 106). However, the Company maintained that the reference forecast projects an average annual increase in adjusted peak load of only 0.57 percent between 1991 and 1995, approximately one-fourth the projected increase of 2.29 percent forecast for the years 1996 to 2000 (SCE Reply Brief at 15 through 18, Exh. EFSC-N-

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[25](…continued)
EFSC-N-63R at 1). SCE further indicated that the reference forecast is closer to the low demand forecast than the high demand forecast (id..).

[26] SCE argued that the Resource Assessment shows NEPOOL members will need 241 MW of additional capacity in 1997, beyond members' currently committed existing and future capacity, to meet the expected value of NEPOOL's 1997 capacity position (SCE Brief at 49, citing, Exh. SCE-RR-6). Although SCE did not provide a regional need forecast based on the Resource Assessment, SCE did provide a Massachusetts need forecast based on an adaptation of NEPOOL's 1992 analysis of expected value capacity position (see Section II.A.4.b., below).

63R at 1).[27] Therefore, SCE characterized the reference forecast overall as overly pessimistic, particularly in the near term (Exh. EFSC-N-63R at 1 through 2).[28]

In explaining its concerns with the short-term results of the reference forecast, SCE indicated that NEPOOL's short-term forecast was based on forecasts of three exogenous variables -- real personal income, number of residential customers and real residential electricity prices (id. at 2). SCE asserted that the short-term forecast was overly pessimistic because (1) the economic and demographic trends reflected were unrealistically low, and (2) electricity price trends were unrealistically high (id. at 7).[29] In addition, the Company questioned the overall objectivity and reliability of the short-term forecast because NEPOOL made ad hoc adjustments to data developed by its own consultants and did not rely solely on objective economic and fuel price forecasts (id. at 3-5; Tr. JH4, at 35-36).[30] SCE noted that the short-term forecast also may have affected the long-term forecast results for 1996 and beyond,

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27 SCE argued that the long-term forecast's economic and demographic assumptions show no basis for such a dramatic difference (SCE Reply Brief at 15 through 16, citing, Exhs. SCE-RR-6, at 2; SCE-RR-7). SCE further argued that forecasted growth for the years over which the short-term and long-term forecasts are merged, 1994 and 1995, is not high enough to eliminate the effects of the short-term forecast (id. at 16 through 17).

28 SCE indicated that the reference forecast adjusted by the 1992 CELT values for DSM reflects a CAGR in adjusted peak load of 1.9 percent over the forecast period (Exh. EFSC-N-62).

29 SCE stated that NEPOOL's forecast of higher real electricity prices in 1992 and 1993 was driven primarily by high short-term fuel price projections (Exh. EFSC-N-63R at 7). SCE stated that NEPOOL made upward adjustments to an objective forecast of 1992 fuel prices and noted that, in addition, NEPOOL's price forecast for residual oil was higher than two other price forecasts (id.).

30 SCE indicated that NEPOOL relied on a modified Delphi method, or opinion poll of members of its Load Forecasting Committee, to forecast the variables underlying the short-term forecast (Exh. EFSC-N-63R at 3). SCE added that this approach is well-known for its failure to predict turns in the economy such as that which New England is currently experiencing (id.).

although Mr. Reed testified that the basis for confirming such an effect is unclear (Tr. 24, at 92 through 98).[31]

Given its concerns, SCE argued that the reference forecast should not be accepted, without adjustments, as a reliable forecast of regional need (SCE Brief at 4). Regarding specific kinds of adjustments to improve the reference forecast, the Company suggested (1) adjustments to reflect SCE's differing economic expectations in the short term and SCE's differing DSM expectations, and (2) consideration of need on a probabilistic basis utilizing NEPOOL's resource adequacy assessment (SCE Brief at 47 through 48, citing, Tr. 24, at 213 through 215). The Company asserted that one way to accomplish an appropriate adjustment of the reference forecast would be to utilize an overall growth rate based on the long-term forecast, for example the 2.3 percent growth rate produced by that forecast for the period 1996 through 2000 (id.).

With regard to the GNP forecast, SCE explained that GNP is the dollar value of the output of goods and services produced by the United States (Exh. SCE-11 at 23). SCE indicated that, in comparing changes in peak load to GNP trends, the GNP forecast effectively

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31 Mr. Reed explained that such an effect could result if NEPOOL's long-term forecast results were in the form of growth rates, and thus applied to a low base produced by the short-term forecast (Tr. 24, at 93). SCE asserted such is a logical inference, given that the economic, demographic and oil price projections used in the reference forecast are expressed in terms of annual escalation rates, not absolute values (SCE Reply Brief at 15, citing, Exhs. SCE-RR-7, SCE-2-DS-6S). Mr. Reed further testified that, even if the short-term forecast does not affect the long-term forecast, upward adjustments to the short-term forecast to address SCE's concerns could necessitate adjustments to forecasted loads beyond 1995 for consistency purposes (Tr. 24, at 96).

reflects industrial production levels, demographic growth, and current economic conditions affecting consumer behavior (id. at 24).[32,33]

As an input to the GNP forecast, SCE indicated that it assumed annual growth in GNP would be (1) 2.4 percent for the years 1990 to 1995, and (2) 2.5 percent for the remaining forecast years (id.).[34] The GNP forecast projects a CAGR of 2.6 percent in peak load over the forecast period (id., attachment E). Relative to other demand forecast methodologies, the Company classified the GNP forecast as a mid-range forecast and, therefore, as the most likely forecast (Exh. SCE-9, at 8).[35]

SCE asserted that the modeled relationship between peak load and GNP, although based on trends over the full 17-year period 1974-1990, is consistent with trends over shorter time spans and, therefore, applicable to year-to-year changes (Exh. EFSC-N-13; Tr. 11, at 78 through 83). SCE further asserted that the GNP forecast would accurately account for the

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32 The GNP forecast incorporates a power coefficient of 1.09, i.e., the forecast reflects that, over time, peak load is proportional to GNP raised to the power 1.09 (Exh. AG-2-1; Tr. 11, at 78).

33 Mr. Kuhn indicated that employment, personal income and various regional indicators provide other measures of economic activity that have a strong correlation with electricity demand (Exh. SCE-11, at 24 through 28). He noted that the forecast was based on the GNP rather than such other measures because GNP data and forecasts were available for longer periods and because GNP is a more inclusive measure (id.).

34 The Company indicated that it based its forecast of GNP growth on a number of available forecasts of GNP, noting that the SCE forecast was slightly above the consensus of other forecasts for 1992 but conservative relative to such consensus for the two-to-five year horizon (Exh. SCE-11, at 30). The Company indicated that the actual 1992 annual growth figure, available at the time of the reopened hearings, was 2.1 percent (Tr. JH5, at 19).

35 The Company assigned relative probabilities to its demand forecast methodologies, using scaled scores based on judgment (Exh. SCE-9, at 11, attached exhibit A). The Company ranked the demand foreast methodologies, from most probable to least probable, as follows: (1) GNP forecast; (2) CAGR reference forecast; (3) 1990 CELT Report forecast; and (4) linear regression forecast (id., attached exhibit 11A).

impact of future utility-sponsored DSM programs if DSM program levels did not increase substantially, in absolute terms, over the forecast period (Tr. JH5, at 87 through 89).

The Company stated that it developed its two remaining forecasts -- the linear regression forecast and the CAGR regression forecast -- based on performing time series regression analysis of 1974-1990 weather-normalized summer peak load data derived from NEPOOL data (Exhs. SCE-9, attached exhibit 2; SCE-11, at 10 through 22, attachments C, D, E; EFSC-N-7). The Company asserted that, by relying on historical trends to forecast future outcomes, time series regression analyses assume that the factors which determined peak load in the past will continue to influence peak load in the future (SCE Reply Brief at 21, citing, Tr. 11, at 27). The Company stated that historic trends in DSM are reflected in the weather-normalized data that underlies SCE's regression equations, and claimed that a moderate to high amount of DSM thus was incorporated in SCE's regression forecasts (Exh. EFSB-MN-4).

The Company asserted that both the linear and CAGR regression equations performed extremely well in terms of statistical results over the 1974-1990 period, although the CAGR regression equation performed slightly better than the linear regression equation (SCE Brief at 26, citing, Exh. SCE-9, at 16).[36,37] The Company indicated that the projected growth in peak

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36 SCE stated that, for the 1974-1990 data series, the CAGR format was superior with respect to the percentage of explained variation ("R^2"), the standard error of estimate, and the durbin-watson statistic (Exh. SCE-11, at 17). Regarding the Durbin-Watson value of 0.72 for the linear format, Mr. Kuhn stated that such a result indicated significant autocorrelation, i.e., correlation between regression equation error values and their previous-year values (id. at 14, 18 through 22). He added that adjustments for such autocorrelation yielded a higher projection of peak demand (id. at 21 through 22).

37 SCE provided a similar comparison of statistical results for the linear and CAGR regression formats using a longer 1969-1990 data series from West Lynn Decision, 22 DOMSC at 16-17, which reflected actual rather than weather-normalized peak load (Exhs. EFSC-2, EFSC-RR-110). The Company's analysis, while showing lower R^2 results than the weather-normalized series generally, indicated that the CAGR and linear formats were nearly equal with respect to R^2 and Durbin-Watson values (Exh. EFSC-RR-110).

load would be 475 MW per year under the linear regression forecast[38] and 2.9 percent per year under the CAGR regression forecast (Exhs. EFSC-N-10a; EFSC-RR-110).

The Company asserted that the linear regression forecast represents a very low case, also claiming that the Siting Council's West Lynn Decision supports the view that a linear regression forecast constitutes an "approximate minimum" for a long-term forecast (SCE Brief at 27; Exh. SCE-11, at 8). The Company asserted that the CAGR regression forecast, the highest forecast over all years of the forecast period, is a conservative representation of a high case (id. at 8).

ii. Position of the Attorney General

The Attorney General argued that the Company's regional reference forecast is biased upward and that the Company's other demand forecast methodologies do not provide a reliable basis for determining need (Attorney General Brief at 41 through 71). The Attorney General's witness, Dr. Shakow, provided alternative testimony relative to: (1) the Company's forecast methodologies; (2) the nature of the current economic recession; and (3) results of an alternate "diagnostic" econometric forecast analyzing inputs and assumptions underlying the reference forecast (Exhs. AG-1, EFSC-N-66, EFSC-N-67).

With respect to the reference forecast, the Attorney General argued that SCE's claim that the forecast's economic assumptions are pessimistic is unfounded and, if anything, those assumptions likely will prove to be unduly optimistic (Attorney General Brief at 45). In support, he argued that (1) the economic assumptions of the reference forecast do not adequately reflect the structural impediments and resultant weakness of the economy, and (2) methodological changes employed by NEPOOL had the effect of increasing the unadjusted load forecast of the reference forecast (id. at 46 through 51).

In discussing the economic assumptions of the reference forecast, the Attorney General disagreed with SCE's conclusion that the economic forecast underlying the reference forecast is

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[38] Over the 1991-2006 forecast period, the linear trend corresponds to a CAGR of 1.9 percent (Exh. SCE-9, Attachment E).

overly pessimistic given that an economic recovery is underway (id. at 44, 48; citing, Exh. EFSC-N-63R at 8-10; Tr. 25, at 82).[39] Dr. Shakow testified that the projected levels of economic activity driving the reference forecast are, if anything, too high (Exh. EFSC-N-67, at 24 through 25). He explained that the United States economy is reflecting business cycle effects as in the past, but that the current recession has been protracted and the recovery dampened due to the structural factors affecting the economy (Exhs. AG-1, at 45 through 53; EFSC-N-67).[40] He predicted a prolonged period of structural adjustment and recovery, noting that business cycle effects will be less prominent while restructuring occurs (Exh. EFSC-N-67, at 25).

In addition, the Attorney General asserted that unjustified methodological changes have led to an increase in the unadjusted load forecast of the reference forecast (Exh. EFSC-N-66b at 10 through 15). He indicated that such changes include changes to: (1) the forecast of electricity prices; (2) the assumptions regarding new technologies; and (3) estimates of productivity (id.). The Attorney General stated that a predicted decline in electricity prices provided the most significant upward pressure on the reference forecast (id. at 12). Dr. Shakow testified that such decline in the electricity price forecast was due to

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39 The Attorney General argued that the majority of Mr. Reed's comments on the reference forecast report pertain to NEPOOL's short-term forecast which ceases to have an effect on NEPOOL's load projections after 1995 (Attorney General Brief at 43, citing, Exh. EFSC-N-63R, Tr. 25 at 6 through 7). Therefore, he argued that the short-term forecast is irrelevant to the Siting Board's determination of need in this case (id.).

40 Dr. Shakow indicated that there are major structural impediments in the United States to robust economic recovery and performance including: (1) debt overhang; (2) decreased prospects for reducing debt burden; (3) scarcity of loanable capital; (4) institutional weakness in the financial and banking sectors; (5) heavy foreign holding of United States debt; (6) declining competitive position of United States industry relative to other industrialized countries; (7) shift away from New England industries; and (8) outmoded and defective infrastructure and capital, including human capital (Exh. EFSC-N-67, at 20 through 25).

unjustified methodological changes including (1) a change in the definition of electricity price,[41] and (2) a change in price forecasting methodology (id. at 13 through 14).[42]

Relative to the incorporation of new technologies into the reference forecast, Dr. Shakow testified that NEPOOL assumptions of forecasted sales of electric vehicles are inappropriate given uncertainties surrounding their acceptance (id. at 12).[43] With respect to productivity, the Attorney General asserted that NEPOOL introduced changes into its model of regional economic activity which led to increased estimates of productivity -- significantly higher than would be expected based on actual growth over the past two decades or current economic conditions (Attorney General Brief at 48 through 49, citing, Exh. EFSC-N-66b at 10 through 12).

In support of the Attorney General's positions, Dr. Shakow presented independent quantitative analyses of regional demand based on a diagnostic utility system model known as

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41 Dr. Shakow explained that in the 1992 CELT report, the traditional rate concept of electricity price was replaced with an "energy services concept" which assumes that a consumer who uses less electricity as a result of the installation of DSM measures would not reduce electricity consumption even further as a result of rate increases (Exh. EFSC-N-66b at 13 through 14). He added that this definition, therefore, biases the price downward and the demand forecast upward (id. at 14).

42 Dr. Shakow explained that previously, a computer model, PROSCREEN was utilized to forecast electricity prices but that for the reference forecast, an aggregation of individual utility company forecasts for components of financial revenue requirements was utilized (Exh. EFSC-N-66b at 14). He stated that the PROSCREEN model accounted for the secondary effects on demand and price of cost-recovery mechanisms while the individual utility forecasts would not take such secondary effects into account, and thus, would bias prices downward (id.).

43 Mr. La Capra noted that the electric vehicle forecast does not impact the long-term forecast until the year 2002 (id. at 68). He stated that it was reasonable for NEPOOL to include the electric vehicle forecast in the long-term forecast as it reflects future potential (id.).

The Siting Board notes that NEPOOL calculated that electric vehicles and miscellaneous other factors contribute to a 0.1 percent higher growth rate for 1991 to 2006 (Exh. EFSC-N-61b at 1-7).

the PURLE model, incorporating a load forecasting module employing econometric specifications (Exhs. AG-1, at 55 through 59; EFSC-N-66S).[44] To project demand, the load forecasting module used multiple regression analysis incorporating three to five economic/demographic variables for each of three customer classes (Exhs. SCE-2-DS-2, SCE-2-DS-8).[45,46] Dr. Shakow indicated that he used the PURLE model to: (1) develop an independent demand forecast utilizing the economic and demographic inputs used in the reference forecast; (2) analyze the relative demand forecast effects of price input differences and economic and demographic input differences between the 1991 CELT report forecast and the reference forecast; and (3) analyze the demand forecast effects of removing or correcting discrete methodological changes introduced by NEPOOL in the reference forecast and not present in earlier CELT Report forecasts (Exh. EFSC-N-66, at 4 through 8).

The PURLE model analysis, using reference forecast inputs, projected a 1992-1998 CAGR of 1.43 percent and a 1992-2007 CAGR of 1.72 percent, as compared to CAGRs of 1.39 percent and 1.92 percent, respectively, under the reference forecast (id. at 8). Comparing

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44 Dr. Shakow stated that the PURLE model, developed by himself and Gibson Economics, Inc., includes three modules -- a load forecasting module, a resource selection module, and a dynamic least-cost resource expansion module -- which can be run individually to address questions of interest, or run consecutively to produce an equilibrated forecast of a set of least-cost resources to serve a necessary load and load shape (Exh. AG-1, at 55 through 56). Dr. Shakow explained that, as a result of simplifications in the design of the PURLE model, it should be considered a diagnostic model rather than a full-scale utility planning program model (Tr. 25, at 33).

45 Dr. Shakow indicated that the load forecasting module first forecasts energy demand by customer class based on user-specified independent variables, then aggregates energy demand and employs a three-point load duration curve model to project base, median and peak load (Exh. AG-2, at exhibit DMS-7).

46 Dr. Shakow incorporated prices of various fuels and activity determinants, including number of households, per capita income and commercial and industrial employment (Exh. SCE-2-DS-8). Dr. Shakow also used dummy variables to reflect data elements specific to particular New England states or particular historical years (Exhs. EFSC-N-66, at 5; SCE-2-DS-8).

forecast results as affected by 1991 and 1992 model inputs, Dr. Shakow indicated that the PURLE model showed a major stimulating effect on demand forecast results based on 1991-1992 price input changes (id. at 7 through 8). He added that the PURLE model, unlike the NEPOOL model, also showed that 1991-1992 changes in economic/demographic inputs helped account for an increase in demand forecast results (id.).[47]

In support of his criticisms concerning methodological changes in the reference forecast, Dr. Shakow used the PURLE model to analyze the effect of removing or correcting identified changes relating to: (1) the definition of electricity price; (2) the use of a sum-of-company price forecast; (3) the assumption of higher productivity; and (4) the use of an electric vehicle forecast (Exh. EFSC-N-66, at 6 through 8). Dr. Shakow reported that his analysis showed NEPOOL's methodological changes all served to increase demand under the reference forecast (id. at 7).[48]

With respect to the GNP forecast, the Attorney General argued that it should not serve as a basis for determining need in that it: (1) omits relevant variables; (2) rests on an unsubstantiated relationship between GNP and peak load; and (3) incorporates an unduly optimistic forecast of GNP (Attorney General Brief at 61 through 68). The Attorney General stated that even though GNP is one determinant of electricity demand, the GNP forecast fails in that it omits primary factors that influence the demand for electricity in New England, including

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47 Based on substituting 1991 economic/demographic inputs for 1992 inputs in the reference forecast model, Dr, Shakow's analysis showed that 1991-1992 changes in such inputs decreased the 1992-2007 CAGR from 2.08 percent to 1.92 percent (Exh. EFSC-N-66, at 8). Utilizing the PURLE model, the 1991-1992 changes in the same inputs increased the 1992-2007 CAGR from 1.65 percent to 1.72 percent (id.).

48 The analysis showed growth rate additions of: (1) 0.11 percent in the 1992-1998 CAGR and 0.06 percent in the 1992-2007 CAGR attributable to the change in definition of electricity price; (2) 0.15 percent in both the 1992-1998 CAGR and the 1992-2007 CAGR attributable to use of the sum-of-company price forecast; (3) 0.28 percent in the 1992-1998 CAGR and 0.26 percent in the 1992-2007 CAGR attributable to the assumption of higher productivity; and (4) 0.01 percent in the 1992-1998 CAGR and 0.07 percent in the 1992-2007 CAGR attributable to use of an electric vehicle forecast (Exh. EFSC-N-66, at 8).

household formation and size, disposable household income, price of electricity and competing fuels, and non-price induced conservation (Attorney General Brief at 62, citing, Exh. AG-1, at 13; Tr. 11, at 5 through 7). The Attorney General further argued that the GNP forecast was statistically validated in terms of its ability to forecast cumulative change over a 17-year historical period, and does not accurately forecast year-to-year change (Attorney General Brief at 63 through 64, citing, Tr. 11, at 66 through 68). Therefore, he argued that the forecast would provide an unreliable basis to predict, for example, the four-year change in peak load from 1992 to 1996 (Attorney General Brief at 64).[49] Finally, the Attorney General argued that the GNP forecast incorporates an inflated forecast of GNP to predict New England peak load (id. at 66 through 68).

The Attorney General also argued that the linear regression forecast and the CAGR regression forecast represent primitive methodologies with demonstrated theoretical and empirical shortcomings, and, therefore, do not provide a reliable basis for forecasting peak load in New England (id. 52 through 60). Dr. Shakow testified that the Company's use of time series regression forecasts assumes that the factors determining load growth persist over both historical and forecast periods, whereas in reality the 1974-1990 period reflected in SCE's regression analyses showed constant shifting from the 1970's energy crisis to the 1980's boom years to the current, nearly intractable recession (Exh. AG-1, at 20). He added that the Company's time series regression forecasts are opaque, in that their inherent level of abstraction precludes any understanding of how forecast errors, i.e., the differences between actual and trended values, relate to particular factors that affect peak load (id. at 21).

With respect to future trends, the Attorney General argued that changes in one or more determining factors could dramatically influence demand, and that the Company provided no reason to expect that any such changes would be likely to offset one another (Attorney General

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[49] The Attorney General argued that the Company's analysis incorporates a 1.09-to-one relationship of peak load to GNP, not the one-to-one relationship the Company cited in support of its GNP forecast (Attorney General Brief at 64, citing, Tr. 11, at 77 through 81).

Brief at 53 through 55). The Attorney General further argued that extrapolation of historical peak load trends fails to incorporate DSM trends, because formal DSM programs did not appear until very late in the historical regression period (id. at 54, citing, Tr. 16, at 139, 142). Finally, taking issue with the Company's assertion that the West Lynn Decision supports the Company's use of the linear regression forecast as a low case, the Attorney General argued that the linear regression forecast in the West Lynn Decision was based on unadjusted load and included a separate forecast of DSM reductions, and thus differed from the Company's application of the linear regression forecast methodology (Attorney General Supplemental Brief at 49 through 50).

iii. Analysis

As noted above, the Company developed demand forecasts based on four different forecast methodologies -- the reference forecast, the GNP forecast, the linear regression forecast and the CAGR regression forecast. With respect to the reference forecast, the Siting Board notes that the CELT report has previously been acknowledged as an appropriate starting point for resource planning in New England and that CELT forecasts have previously been accepted for the purposes of evaluating regional need in reviews of proposed NUG facilities. See, e.g., Cabot Power Decision, 2 DOMSB at 272; Altresco Lynn Decision, 2 DOMSB at 43; EEC (remand) Decision, 1 DOMSB at 442; EEC Decision, 22 DOMSC 234-236; NEA Decision, 16 DOMSC at 354. Specifically, the reference forecast in this case has been accepted by the Siting Board as an appropriate base case forecast for use in the analysis of regional need. Cabot Power Decision, 2 DOMSB at 273-274; Altresco Lynn Decision, 2 DOMSB at 43; EEC (remand) Decision, 1 DOMSB at 442.

Here, both the Company and the Attorney General expressed concerns with the reference forecast. As noted above, SCE characterized the reference forecast as overly pessimistic, particularly in the near term, while the Attorney General characterized the reference forecast as likely to overstate demand.

With respect to the Company's criticisms of the CELT forecast -- overly pessimistic economic trends and high fuel price projections -- the Siting Board notes that such criticisms relate primarily to the short-term forecast. Although the Company claims that dampening of demand in the short term may impact the forecast beyond the 1994 to 1995 transition period, given NEPOOL forecast methodology, it is unclear that any such dampening would significantly impact the forecast in the long term. To develop the reference forecast, NEPOOL produced two separate forecasts -- a short-term forecast, based on an econometric model for the years 1992 and 1993, and a long-term forecast based on an end-use model for the years 1996 and beyond -- and then merged the two forecasts to produce projections for the years 1994 and 1995. Thus, the Siting Board agrees with the Attorney General that even if demand were biased downward for the 1992 to 1993 time frame of the short-term forecast, it is not clear that any downward bias would have a significant influence on the long-term forecast for the years 1996 and beyond, the critical time frame of need for the proposed facility. In addition, the Company acknowledged that the reference forecast was a reasonable long-term forecast.

The Attorney General, on the other hand, characterized the reference forecast as likely to overstate demand, due, primarily, to the electricity price forecast methodology, the regional economic activity forecast and the electric vehicle forecast, all part of the long-term forecast. The Siting Board notes that, even if the electric vehicle forecast is inappropriate, the electric vehicle forecast is negligible through the year 2000 and has a minimal impact on the forecast overall. In addition, the Siting Board notes that the record does not support a conclusion that the methodological changes within the electricity price forecast or assumptions regarding regional economic activity were unreasonable or that forecast methodology or assumptions produced unreasonably low electricity prices or augmented growth rates to significantly bias the forecast upward.

In sum, the record does not demonstrate that the reference forecast is obviously biased, either upward or downward such as to lead the Siting Board to question the validity of the forecast. Further, the reference forecast has a wide level of recognition for capacity planning purposes in the New England region and has been incorporated directly into SCE's analysis without the need for adaptation by the proponent. Thus, the Siting Board finds that the reference forecast is an appropriate base case forecast for use in the analysis of regional demand for the years 1996 through 2006.

With respect to the GNP forecast, the Company characterized the forecast as a mid-range demand forecast while the Attorney General argued that the forecast was based on an inflated forecast of the GNP and was methodologically unsound. In previous reviews of proposed NUG facilities, the Siting Board and Siting Council have accepted forecasts based on the historical relationship between GNP, or the related economic indicator GDP, and peak load as alternative forecasts in evaluations of regional need, while recognizing that such forecast methodologies were not sophisticated. See, EEC (remand) Decision, 1 DOMSB at 444-445, Enron Decision, 23 DOMSC at 44, EEC Decision, 22 DOMSC at 236-237. In recent review of a GNP or GDP forecast, the Siting Board found that possible adjustments, however, may be needed to reflect DSM trends over the forecast period. EEC (remand) Decision, 1 DOMSB at 444-445.

Regarding the Attorney General's position that the GNP forecast is biased upward, two possible explanations for any such bias must be addressed (1) that the forecast of GNP itself is high, and (2) that the Company's estimate of the historical relationship between GNP and peak load results in an upward bias. With regard to the Company's forecast of GNP, we recognize that such forecasts are by their nature relatively uncertain and open to subjectivity. However, based on the record, the possibility that over-optimistic economic assumptions underlie the GNP forecast is not compellingly greater than the possibility that overly pessimistic economic assumptions underlie the CELT forecast, as claimed by SCE. With respect to the historical relationship between the GNP and peak load, although year-to-year differences in that relationship raise questions as to its reliability for short-term forecasts, the record supports the validity of the identified relationship as an indicator of historical long-term trends.

Overall, the Siting Board finds that the GNP forecast provides an acceptable forecast for consideration in an analysis of regional demand, while recognizing that the forecast methodology is not sophisticated and that possible adjustments may be appropriate to reflect

DSM trends over the forecast period. We further note that this forecast should not be considered for use as a base case forecast.

With regard to the linear regression forecast and the CAGR regression forecast, the Company maintains that both time series regression formats provided good statistical results and are consistent with Siting Council precedent, while the Attorney General criticizes the time series forecasts as primitive approaches that abstract from the business cycle and are not suitable for determining need in the short or intermediate term. In two additional areas of contention, the Company argues that (1) its time series regression forecasts adequately capture a moderate to high amount of DSM, and (2) its linear regression forecast represents a minimum forecast based on Siting Council precedent, although the Attorney General disputes both points.

As argued by the Company, the Siting Council previously accepted time series regression forecasts for purposes of establishing need. West Lynn Decision, 22 DOMSC at 27-32, 34. In later reviews, time series regression forecasts have been reviewed in conjunction with other forecasts, including in all cases one or more forecasts based on the CELT report. Altresco Lynn Decision, 2 DOMSB at 45-46; EEC (remand) Decision, 1 DOMSB at 481-483. Here, half of the Company's 12 demand forecasts are based on time series regression.

The Siting Board agrees with the Attorney General's position that time series regression provides no means to capture possible shifts in peak load trends stemming from changes in underlying economic determinants, and thus is an unsophisticated forecast methodology. See, Altresco Lynn Decision, 2 DOMSB at 45-46; EEC (remand) Decision, 1 DOMSB at 481-482. However, we disagree with the Attorney General's argument that outright rejection of SCE's time series regression forecasts is warranted. Rather, evidence of theoretical factors that detract from the applicability of a time series regression or other trending forecast, affects the weight the Siting Board places on such forecasts in its determination of need. See, EEC (remand) Decision, 1 DOMSB at 481-482.

With regard to reflection of DSM, the Siting Board questions the Company's assumption that its time series regression analyses, based on a 1974-1990 historical period, can adequately capture current rates of DSM implementation. As argued by the Attorney General, formal utility-sponsored DSM programs did not appear until late in the historical period used in the Company's regression analyses. Therefore, unless annual amounts of DSM implementation are significantly smaller over the forecast period than in recent years, the Company's time series regression forecasts cannot fully capture DSM trends. See, Altresco Lynn Decision, 2 DOMSB at 45-46; EEC (remand) Decision, 1 DOMSB at 482.

Finally, the Siting Board disagrees with the Company's position that Siting Council precedent supports a conclusion that the Company's linear regression forecast is an "approximate minimum" forecast. First, as argued by the Attorney General, the extrapolated linear regression trend in the West Lynn Decision review was adjusted for DSM in order to derive a demand forecast, as distinct from SCE's linear regression forecast approach which ignored DSM. Second, the Siting Council's holding in the West Lynn Decision was premised on an absence of theoretical factors warranting consideration of lower forecasts. Here, the Attorney General's case concerning possible recent and ongoing structural changes in the New England and national economies, although supported by scant evidence, represents to a limited degree the type of theoretical factor that potentially could warrant consideration of a slower long-term growth trend than reflected in a linear regression analysis of past peak load levels. See, EEC (remand) Decision, 1 DOMSB at 482.

Overall, time series regression analyses are a long-recognized benchmark for establishing peak load trends, and have been considered in previous reviews of proposed generating facilities. Therefore, based on the foregoing, the Siting Board finds that the linear regression forecast and the CAGR regression forecast provide acceptable forecasts for use in an analysis of regional demand, while recognizing that the forecast methodologies are not sophisticated and possible adjustments may be appropriate to reflect DSM trends over the forecast period. We further note that neither of these forecasts should be considered for use as the base case forecast.

c. DSM

i. Description

SCE indicated that, in order to incorporate DSM savings from utility-sponsored programs into the CELT forecast, NEPOOL first projects DSM savings over the forecast period by aggregating the DSM forecasts of the individual utilities (Exhs. EFSC-N-64, AG-4-14; Tr. 24, at 32, 35 through 36). SCE stated that NEPOOL then deducts its projection of DSM savings from the load forecasts derived from its short-run and long-run load forecasting models (Exh. SCE-16, at 14).

However, SCE asserted that NEPOOL projections of DSM savings likely overestimate the savings that the region will actually experience as a result of utility-sponsored programs (Exhs. EFSC-N-64; SCE-22, at 8). In support, Mr. Reed stated that in previous CELT forecasts NEPOOL consistently has overestimated the contribution of DSM resources to peak demand reduction (Exh. EFSC-N-64, and attached exhibit N-64.1). Specifically, he stated that for the period 1988 through 1991, actual DSM savings, on average, have been approximately 21 percent less than the DSM forecast by NEPOOL (id.).[50]

As an underlying reason for past overforecasting, SCE stated that utility projections are based on engineering estimates, i.e., calculations of the average savings achievable from a particular DSM measure, and that such estimates generally over-predict actual savings as measured by impact evaluations (id.; Exh. AG-4-20; Tr. 24, at 36 through 54; Tr. JH6, at

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50 The Company indicated that an analysis of NEPOOL DSM forecast accuracy indicates that: (1) actual DSM was less than the 1988 forecast of DSM by 9.8 percent for 1988, 16.4 percent for 1989, 14.3 percent for 1990 and 5.9 percent for 1991; (2) actual DSM was less than the 1989 forecast of DSM by 50.4 percent for 1989, 49.4 percent for 1990, and 35.0 percent for 1991; (3) actual DSM was less than the 1990 forecast of DSM by 12.8 percent for 1990 and 12.0 percent for 1991; and (4) actual DSM was less than the 1991 forecast of DSM by 5.4 percent for 1991 (Exh. EFSC-N-64, attached exhibit N-64.1).

9 through 11).[51] Based on a review of utility impact evaluations filed as part of the MDPU preapproval process for DSM funding, Mr. Reed stated that, on average, actual DSM savings have been approximately 50 percent of estimated savings (Exh. EFSC-N-64).

Regarding specific sources of uncertainty in current DSM forecasts, Mr. Reed testified that conservation on peak is difficult to predict but accounts for a majority of projected reductions in peak load from DSM (Exh. SCE-16, at 15). Noting that easy, cost-effective measures, such as lighting programs, have accounted for large portions of past savings, SCE asserted that improvements in savings are likely to decrease over time (Exh. EFSC-N-64). Citing effects of the economic downturn, the Company further stated that, after utilities submitted 1992 DSM forecasts to NEPOOL, there were reductions in DSM budgets, reductions in load management programs, and increased regulatory concerns with rate impacts, all of which would decrease actual future DSM savings below projections (Tr. JH6, at 6 through 7; Tr. JH1, at 45 through 47).

SCE stated, therefore, that it would be inappropriate to evaluate regional need for new capacity based on the assumption that 100 percent of the utilities' projected DSM savings would be achieved, and instead, a more realistic DSM scenario should be considered (Exh. EFSC-N-64). Thus, for its regional need analysis, SCE provided an alternative DSM forecast as a base DSM case which assumed that DSM growth above 1991 levels would be 50 percent less than the growth forecast by NEPOOL (Exh. EFSC-N-62).

SCE also provided high DSM cases and low DSM cases in conjunction with its demand forecast methodologies. In conjunction with the reference forecast, SCE provided (1) two demand forecasts it views as reflecting high DSM estimates, one based on NEPOOL's 1992 CELT DSM forecast and one based on NEPOOL's 1991 CELT DSM forecast, and (2) a demand forecast based on a low DSM case, the 1989 Resource Assessment DSM projection with a 90 percent probability of being exceeded (id.). In conjunction with the alternative forecast methodologies, however, SCE presented demand forecasts based on different high and

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51 Mr. La Capra stated that some reasons for overestimates include technical problems and customer behavior changes (Tr. JH6, at 9).

low DSM cases obtained from NEPOOL's 1990 Resource Assessment, specifically, a high case based on NEPOOL's 1990 DSM forecast with a 10 percent probability of being exceeded and a low case based on NEPOOL's 1990 DSM forecast with a 90 percent probability of being exceeded (Exhs. SCE-1, at 4-7, 4-20;
EFSC-N-48, table EFSC-N-48b).[52]

ii. Positions of the Intervenors and Company's Response

The Attorney General argued that the Company understated future DSM levels by (1) discounting NEPOOL projected DSM increases over 1991 levels by 50 percent in the base case, and (2) failing to consider potential DSM savings beyond those contained in the reference forecast (Attorney General Brief at 79 through 93; Attorney General Supplemental Brief at 50 through 54, 95 through 101). The Attorney General's witnesses, Mr. Horowitz and Dr. Shakow, provided testimony indicating that the amount of DSM savings included in the reference forecast understates potential future utility-sponsored DSM (Exh. AG-10).

The Attorney General argued that concerns identified by SCE regarding NEPOOL DSM projections -- NEPOOL's historical track record in projecting savings from DSM programs, differences between anticipated and measured savings for particular DSM programs, and uncertainty concerning sustainability of past DSM savings rates in lighting and other programs, and uncertainty concerning DSM prospects as reflected in the 1992 resource assessment -- provide insufficient justification for discounting NEPOOL DSM projections (Attorney General Brief at 81-91; Attorney General Supplemental Brief at 51-54). The Attorney General stated that although SCE calculated NEPOOL's average forecast error for 1988 through 1991 to be 21 percent, the average error for DSM estimates in the 1990 and 1991 CELT Reports is approximately 10 percent (Attorney General Brief at 81, citing,

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52 The Siting Board notes that, in the 1992 Resource Assessment, NEPOOL identified (1) a high DSM forecast with a 10 percent probability of being exceeded, and (2) a low DSM forecast with a 90 percent probability of being exceeded (Exh. SCE-RR-6). In response to a request by the Siting Board, the Company also evaluated need based on NEPOOL's 1991 high DSM forecast (Exh. HO-RR-126).

Exh. EFSC-N-66S at 4). He added that the forecast error for DSM estimates in the 1989 CELT forecast represents an outlying high forecast error, i.e., an error which is significantly higher than that for other years, and that SCE's inclusion of that 1989 forecast error was unjustified (id.).[53]

With respect to the Company's attempt to discredit utility DSM projections by comparing engineering estimates to actual savings, Dr. Shakow asserted that the Company's methodology was flawed (Exh. EFSC-N-66S, at 2).[54] Specifically, Dr. Shakow stated that utility submissions of projected DSM savings reflect planning estimates rather than the field engineering estimates assumed by the Company (id. at 10).[55] He also stated that, in the current regulatory environment, utilities are likely to underestimate savings of individual DSM programs in order to avoid negative performance reviews (id. at 10 through 11). Regarding DSM savings from lighting and other programs, the Attorney General disputed SCE's claim that such savings will not increase in the future as much as in the past, arguing that SCE (1) overlooked the extent of on-going non-lighting programs, (2) overlooked potential technological advances in lighting programs, and (3) assumed without evidence that non-lighting

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53 In addition, Mr. Horowitz indicated that the Company's analysis does not account for an overall decrease in NEPOOL DSM forecast errors due to the utilities' increasing understanding of the amount of DSM that can be delivered due to increasing field experience and evaluation (Tr. JH1, at 180 through 183).

54 The Attorney General argued that Mr. Reed relied on flawed empirical evidence to develop a 50 percent discount factor, based on a discussion of only three New England utilities, and noted that a more thorough analysis supported a discount factor of at most 30 percent, probably less (Attorney General Brief at 90 through 91, citing, Exh. EFSC-N-66S at 7 through 8). Dr. Shakow asserted that, even if Mr. Reed is correct in assuming that field engineering estimates are the basis of utility submissions to NEPOOL, a discount rate for New England should not be based on such limited data (Exh. EFSC-N-66S at 7).

55 Mr. Horowitz stated that planning estimates are developed before programs are implemented and reflect the utility's estimate of customer participation, measures installed, savings per measure, program costs, hours of use, etc. (Exh. AG-200, at 13). He stated that field engineering estimates are estimates of savings based on program delivery (id. at 14).

programs are harder to implement and less cost-effective than lighting programs (Attorney General Brief at 82 through 85, citing, Exh. EFSC-N-66S at 5 through 11, 13, attachment A at 2; Tr. 24, at 172 through 175, 180 through 181; Tr. 25, at 8 through 9).

CLF also argued that SCE failed to substantiate its claim that any significant portion of utility-estimated DSM savings in the CELT forecast is based on field engineering estimates, or that the estimates actually provided to NEPOOL materially overstate DSM savings (CLF Brief at 4). CLF claimed the record shows that: (1) New England's three largest utilities, the New England Electric System ("NEES"), Northeast Utilities ("NU") and Boston Edison, do not rely on engineering estimates to calculate DSM savings; (2) no significant degree of DSM savings data reflected in the CELT forecast is based on raw engineering estimates; and (3) detailed utility examples highlighted by Mr. Reed fail to show that raw engineering estimates form the basis of DSM savings estimates provided to NEPOOL (id. 4 through 16).

The Attorney General also argued that SCE ignored the 1992 Resource Assessment DSM forecast as a basis for considering uncertainty regarding future DSM levels (Attorney General Supplemental Brief at 52). The Attorney General indicated that, although the expected value of that DSM forecast is lower than the 1992 CELT DSM forecast, the difference would support an adjustment of a fraction of the amount reflected in the Company's adjustment to the 1992 CELT DSM forecast (id., citing, Exhs. EFSB-MN-2, at 2 through 3; SCE-RR-6S at 32, 56 through 60; SCE-22, att. RLC-9).[56,57]

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[56] Specifically, the Attorney General argued that the difference between the expected value and reference DSM forecasts is one-third the 25 percent adjustment to the reference DSM forecast reflected in SCE's Massachusetts need analysis (Attorney General Supplemental Brief at 52) (see Section II.A.4.b., below). Assuming the relative DSM forecast levels as represented in the Attorney General's argument, the Siting Board notes that the difference corresponds to one-sixth the 50 percent adjustment to the reference DSM forecast reflected in SCE's regional need analysis.

[57] In addition, the Attorney General stated that the Company's DSM projections fail to account for the DSM resources that NEPOOL considers to be available, with short lead times, and implementable during the 1993-1997 time period (Attorney General Supplemental Brief at 52 through 53). The Attorney General noted that the Resource

(continued...)

In addition to disputing the Company's claim that NEPOOL overforecasts DSM, the Attorney General asserted that the utilities in the region could deliver twice the amount of additional cost-effective DSM currently assumed by NEPOOL for each of the next 15 years, and thus, any need for additional resources could be met by additional DSM (Exh. AG-10, at 2 through 3; Tr. JH1, at 23 through 24, 26, 34 through 35).[58] In support, Mr. Horowitz added that utility submissions to NEPOOL do not represent the maximum levels of DSM savings that utilities currently could achieve and that the reference forecast does not reflect the maximum levels of cost-effective DSM that will be available over the forecast period (Tr. JH-1, at 3 through 15). Mr. Horowitz stated that his assessment of increased DSM potential considers rate impacts, technological feasibility and management issues, cost-effectiveness of programs and effects of the current economic downturn (id. at 156 through 160).

Mr. Horowitz identified a number of specific factors indicating that higher DSM could be achieved including: (1) a regulatory shift away from requiring aggressive conservation efforts and toward a balancing of DSM with associated rate impacts; (2) a lack of utility commitment in acquiring maximum DSM resources; and (3) recent program oversubscription resulting from demand by customers for a greater level of DSM services than provided (Exh. AG-10, at 3 through 8; Tr. JH1, at 168 through 169). Mr. Horowitz also cited program operating experience which suggests that delivery of DSM programs could be increased, and identified expected technological improvements which could increase energy efficiency and

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[57](…continued)
Assessment considers potential DSM contingency programs that would be implementable within the 1993 to 1997 time period and would bring DSM impacts above the level in NEPOOL's high DSM forecast (id.). In addition, he stated that the Company failed to account for potential interdependency of load growth and DSM (id. at 53 through 54).

[58] The Attorney General noted that one utility, Western Massachusetts Electric Company, has in the last year filed with the Department a proposal for a set of programs that would double its DSM savings reflected in the 1992 CELT report (Attorney General Supplemental Brief at 96 through 97, citing, Tr. JH1, at 24 through 25).

provide significant savings during the forecast period but are not reflected in utility DSM forecasts (Exh. AG-10, at 9 through 10, 12 through 15; Tr. JH1, at 169).[59]

SCE responded that the Siting Board should reject the Attorney General's argument that the NEPOOL DSM projections could be doubled because the Attorney General failed to consider issues that affect implementation of DSM programs including cost effectiveness and regulatory approval (SCE Reply Brief at 41 through 45). SCE further responded that the Company's base DSM case is the best estimate for determining the contribution of DSM toward providing a necessary energy supply for the Commonwealth (id.).[60]

iii. Analysis

The Company considered a discount of the 1992 CELT DSM by 50 percent of the increment over 1991 levels to be appropriate in the base case, while the Attorney General argued that such discounting is excessive and argued instead, that the forecast should reflect a doubling of the 1992 CELT DSM levels. The Siting Board agrees with the Attorney General that SCE's discounting of DSM is excessive. The average actual DSM underperformance for the years 1988 through 1991 is 21 percent, significantly lower than the 50 percent assumed by the Company.

In reviewing a similar analysis of NEPOOL overforecasting of DSM in the EEC (remand) Decision, the Siting Board noted that the high level of overforecasting in the 1989 CELT forecast is not based on historical trends and may be an aberration, contributing to an unwarranted high under-performance average. 1 DOMSB at 445. Thus, the Siting Board concluded in that review that it would be reasonable to omit DSM under-performance from

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[59] Mr. Horowitz indicated that such technologies include high-efficiency office equipment and refrigerators and microwave clothes dryers (Exh. AG-10, at 13).

[60] With regard to the Attorney General's argument regarding a filing by WMECo with the Department that would double DSM savings, the Company asserted that there is no evidence in the record that WMECo has made such a filing, and that utilities in the region are not planning such that DSM savings would be doubled in each year of the planning horizon (SCE Reply Brief at 43 through 45).

1989 in considering the historical basis for any discounting of NEPOOL-projected DSM levels. Id. at 445-446. See also, Cabot Power Decision, 2 DOMSB at 279-280; Altresco Lynn Decision, 2 DOMSB at 49-50.

By omitting the actual DSM under-performance for 1989 and substituting instead the DSM under-performance for 1990, the next largest DSM under-performance, the average DSM under-performance for the 1988 to 1991 Celt Forecasts is reduced to 11.4 percent. Therefore, based on the foregoing, the Siting Board finds that it is appropriate to adjust the 1992 CELT DSM by 11.4 percent of the increment over 1991 levels and that such adjusted level represents a reasonable base DSM case for the purposes of this review.

Accordingly, the Siting Board finds that it is appropriate to adjust the 1992 CELT DSM levels in the base case. The Siting Board further finds that an adjustment of the 1992 CELT DSM levels by 11.4 percent of the increment over 1991 levels is reasonable for the purposes of this review.

The Siting Board notes that the Company's regional need analysis relies on DSM projections from previous CELT Report forecasts to provide various high DSM cases and low DSM cases for use in conjunction with its different demand forecasts. Although the Company states it included some such forecasts to broaden the bandwidth of alternative DSM levels included in the analysis, use of dated projections provides an arbitrary basis to develop such a range. The Company provided no justification for assuming low DSM cases and high DSM cases that are lower than the low DSM forecast and the high DSM forecast, respectively, as included in the 1992 CELT Report.

Accordingly, for the purposes of this review, the Siting Board finds that the Company's low DSM forecast should be adjusted to represent the 1992 CELT low DSM forecast. Further, for the purposes of this review, the Siting Board finds that the Company's high DSM forecast should be adjusted to represent the 1992 CELT high DSM forecast.

Finally, while we agree with the Attorney General that increased DSM implementation potentially could occur over the forecast period as a result of policy shifts by utilities and regulators, the Siting Board does not agree that a doubling of the 1992 CELT reference DSM levels should be reflected in the Company's forecast. The Attorney General did not adequately support the assumption that DSM levels could or would be doubled. Given the significant policy changes that would be required for such an increase in DSM implementation, the Siting Board notes that a scenario which assumes the doubling of 1992 DSM levels would be more appropriately considered as a possible contingency rather than as a base or even a high DSM case. See, EEC (remand) Decision, 1 DOMSB at 446.

d. Supply Forecasts

i. Description

(A) Capacity Assumptions

The Company presented three supply forecasts based on the 1992 CELT report -- a base supply case, high supply case and low supply case (Exhs. EFSC-N-62, EFSC-N-65).[61] The Company asserted that the CELT Report provides a comprehensive data base of all utility and non-utility resources within the region and purchases from outside the region (Exh. SCE-16, at 16). SCE provided its regional base supply case in May 1992, based directly on the 1992 CELT report with no announced updates (Exhs. EFSC-N-62, EFSC-N-64).[62]

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[61] The Company initially provided supply forecasts based on the 1990 CELT Report, and also provided two earlier updates of the supply forecasts based on (1) the 1991 CELT Report, and (2) supply resource changes announced by NEPOOL in early 1992 (Exhs. SCE-1, at 4-15 through 4-18; SCE-9, at 9; EFSC-RR-126).

[62] The resources included in the 1992 CELT Report include: (1) existing utility generation; (2) cumulative retirements; (3) cumulative life extensions; (4) committed non-utility generation; (5) net of planned purchases and sales; (6) other committed capacity additions; and (7) net re-ratings and deactivations (Exh. EFSC-N-61a). Included in the committed non-utility generator ("NUG") category are all operating units and committed NUGs under NEPOOL category "UC," defined as "under construction and/or fully licensed" (id. at 55). This category includes 181 MW for the AES Thames facility in Connecticut and 222.69 MW for the MASSPOWER facility in Massachusetts (id. at 69). The Company indicated that the MASSPOWER facility has approximately 3 MW for sale and the AES Thames facility, which has been completed

(continued...)

To provide a higher supply forecast, the Company stated that it developed a high supply case which assumes that the base supply case is increased by (1) the continuation of the Hydro-Quebec Phase II contract beyond its scheduled expiration of July 1, 2001, and (2) 50 percent of the proposed, but not yet committed, utility generation project capacity (Exhs. SCE-1, at 4-15; EFSC-N-62).[63] To provide a lower supply forecast, the Company stated that it developed a low supply case which assumes that the base supply case is decreased to reflect loss of the 1,150 MW Seabrook unit or some other comparably sized resource (id.).[64]

In addition, the Company provided 16 additional supply scenarios as contingency adjustments to its base, high and low supply cases (Exhs. SCE-1, at 4-15 through 4-26; SCE-9, at 9-11; EFSC-N-48; EFSC-N-62).[65] SCE indicated that contingency adjustments that would increase supply included: (1) the addition of 46 percent of planned but uncommitted NUG projects;[66] (2) the addition of 66 percent of planned but uncommitted NUG projects; (3) the

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[62](…continued)
has approximately 20 MW of uncommitted capacity (Exh. EFSB-MN-8). However, the Siting Board notes that that the AES Thames facility is a 180 MW facility.

[63] Among the principal proposed utility projects that SCE included from this category are (1) two projects adding capacity at the MMWEC Stonybrook facility, totaling 165 MW, and (2) the Edgar Energy Park, a proposed 306 MW facility (Exh. EFSC-N-62). Although the proposed TEC facility also was included in the 1992 CELT Report as a proposed TMLP facility, SCE excluded its own project from its high supply case (id.).

[64] SCE asserted that the low supply case is representative of the expected value of combined utility and non-utility unit attrition as identified in the 1992 Resource Assessment, amounting to 1,093 MW in 1996 and 1,288 MW in 1997 (SCE Reply Brief at 28 through 29, citing, Exh. SCE-RR-6S, Technical Supplement at 367).

[65] In conjunction with its overall analysis of supply, the Company assigned relative probabilities for its supply forecasts and contingency cases, using a scoring scale based on judgment (Exh. SCE-9, at 11, attached exhibit 11A).

[66] Even though the Company indicated that this contingency category includes planned but "uncommitted" NUG projects, this contingency category includes NUG projects under (continued…)

addition of 25 percent of planned but uncommitted NUG projects;[67] and (4) the life extension of 25 percent of the capacity of units currently scheduled for retirement (id.). SCE indicated that contingency adjustments that would decrease supply included: (1) the retirement of 25 percent of the capacity of existing units currently operating beyond limits defined by NEPOOL guidelines; (2) delay until 1996 in the availability of the Seabrook unit; (3) delay until 1993 in the availability of the Hydro-Quebec Phase II capacity; (4) one year delay in availability of 70 percent of committed but uncompleted NUG projects; (5) two-year delay in committed (existing and uncompleted) gas NUG projects based on gas supply shortages; and (6) reduction in availability of committed (existing and uncompleted) coal units based on changes in environmental regulations (id.).[68] Finally, SCE indicated that it also developed six sets of double-contingency adjustments, all of which would have the net effect of reducing supply,

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[66](…continued)
NEPOOL category "C," defined by NEPOOL as "signed power contract with utility, financing not obtained. Not under construction." (Exhs. SCE-9. at 9-11; EFSC-N-61A at 55). Therefore, NEPOOL category "C" includes only the committed capacity of planned NUG projects. The Siting Board notes that this category includes 83 MW for the committed capacity of the Enron Power Enterprises, Inc. ("Enron") facility (Exh. EFSC-N-61A at 73). During the course of the hearings, the Company indicated that the Enron facility, which has an uncommitted capacity of approximately 60 MW, was now under construction (Exh. EFSB-MN-8). In updating information relative to the supply for the Massachusetts need analysis, SCE added 58 MW for Enron committed capacity to the base case for the prorated share to Massachusetts and removed a similar capacity from this contingency category and also decreased Massachusetts purchases from the Power Authority of the State of New York ("PASNY") based on updated data which indicated original estimates were too high (Exh. SB-JH-RR-11). The Company did not apply either of these adjustments to the regional supply forecast.

[67] SCE termed the 66 percent NUG-success-rate contingency and the 25 percent NUG-success-rate contingency as "different futures," which analyze the sensitivity of SCE's need forecasts to variation in basic input parameters (Exh. SCE-9, at 10 through 11).

[68] SCE indicated that the federal Clean Air Act, Massachusetts acid rain legislation and other potential new legislation could lead to the retirement of certain older fossil fuel-fired units (Exh. AG-RE-77).

based on combinations of five of the above contingencies, specifically combinations of each of the three contingencies incorporating capacity from uncommitted NUGs at differing success rates, with the two contingencies relating to delayed gas NUG availability and reduced coal unit availability (id.).

(B) Reserve Margin

The Company indicated that it assumed a forecast period reserve margin of 22.5 percent of peak demand for supply forecasts which included the capacity of the Seabrook nuclear unit, and a 20 percent reserve margin for supply forecasts which did not include the capacity of the Seabrook unit (Exhs. SCE-1, at 4-14; EFSC-N-62). SCE indicated that NEPOOL sets annual reserve margins based on (1) reliability criteria reflecting the cumulative loss-of-load probability faced by NEPOOL, and (2) the size and the likelihood of the system's largest units failing (Exh. SCE-1, at 4-14). The Company acknowledged that it would be reasonable for NEPOOL to decrease the reserve margin slightly if Seabrook reaches a mature level of operation, and that such a possibility should be considered in the need analysis (SCE Supplemental Reply Brief at 23, citing, Exh. SB-JH-RR-11).[69] In response to a request of the Siting Board Staff, the Company also prepared an analysis reflecting a lower reserve margin resulting from an assumed Seabrook maturity
(Exh. SB-JH-RR-11).

ii. Positions of the Intervenors and Company's Response

(A) Capacity Assumptions

The Attorney General argued that the Company's supply forecast is understated due to the omission of certain supply options from the base supply case (Attorney General Supplemental Brief at 54 through 57). First, the Attorney General stated that the Company's

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69 The Company stated that there is no guarantee that a large nuclear unit such as Seabrook would ever reach the improved availability associated with mature operation (SCE Supplemental Reply Brief at 23, citing, Exh. SB-JH-RR-11).

base supply case includes only the committed portion of NUG units that are existing or under construction, but instead, should include the entire capacity of these units (id. at 54 through 56).[70] Next, the Attorney General stated that the extension of the Hydro-Quebec contract beyond the year 2000 also is omitted from the base case even though the Company did not evaluate the availability of the Hydro-Quebec resource beyond the year 2001 (id. at 56 through 57). He stated that the capacity position of the region would significantly improve if the Hydro-Quebec contract were extended beyond the year 2000 and that it would, therefore, be irresponsible to plan new power plants based on the assumption that Hydro-Quebec would cease supplying power as of 2001 (id. at 56-57, citing, Tr. JH8, at 8).

The Attorney General further argued that the Company's low and high supply cases also understate supply, especially in the early years of the forecast period (Attorney General Brief at 72 through 75). He maintained that SCE provided no justification for assuming the unavailability of the Seabrook nuclear unit, or a facility or facilities of equivalent size, as part of the low supply case (id. at 74). In addition, he maintained that the low supply case overlaps with contingency cases assuming (1) a 25 percent reduction in life extensions and (2) retirement of fossil fuel generating facilities due to changes in environmental regulations, thus, double-counting capacity subtractions (id. at 74 through 75).

The Attorney General asserted that the high supply case is a reasonable base supply case rather than an optimistic scenario, given that it assumes (1) a Hydro-Quebec contract extension which would not affect supply until the year 2001, and (2) a 50 percent success rate for those utility additions which are planned but not utility-authorized and those for which regulatory approval is pending (id. at 73 through 74, citing, Exh. EFSC-N-1B, Appendix A at 54).

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[70] The Attorney General argued that the entire capacity of the Enron facility, 146 MW, should be included in the Company's base supply case and that the uncommitted capacity of the MASSPOWER and AES Thames facilities totalling 23 MW should be included as well (Attorney General Supplemental Brief at 54-55).

In addition, the Attorney General argued that the Company's contingency analysis is far more sensitive to contractions in supply than it is to expansions in supply (id. at 78). He argued that, in particular, SCE's delayed-Seabrook contingency, like the no-Seabrook supply forecast, unreasonably understates likely future supply (id.). He also argued that one contingency assumes an unduly pessimistic 46 percent success rate for all planned NUG projects, while nine other contingency cases, like the base supply case, unrealistically assume that no NUG projects other than those already under construction or with full regulatory approval will become available in the forecast period (id. at 76 through 77). Finally, the Attorney General argued that the contingency assuming a 25 percent reduction in life extensions overlaps the contingency assuming retirement of certain coal-fired units, among other units, due to changes in environmental regulations (id. at 77 through 78).

With respect to the base supply forecast, SCE responded that an assessment of committed resources must be made before NEPOOL or a utility can identify a resource need and then assess the appropriate mix of supply resources (SCE Reply Brief at 29). With respect to the low supply forecast, SCE responded that the 1,150 MW supply reduction reflected therein is comparable to the expected value of combined utility-unit attrition and NUG-unit attrition identified by NEPOOL in the Resource Assessment (id. at 29).

With respect to the Attorney General's argument that the Company's supply scenario analysis does not reflect a neutral criterion for selecting scenarios and are biased toward supply contractions, the Company responded that its supply scenarios were tailored to address particular concerns or combinations of concerns, and should not be rejected merely because the impacts on supply are similar between scenarios (id. at 33).

(B) Reserve Margin

The Attorney General argued that the Company's assumed reserve margin of 22.5 percent is unreasonably high (Attorney General Supplemental Brief at 57). The Attorney

General argued that, at most, the reserve margin should be 21.7 percent (id. at 58).[71] He also argued that reserve margins should even be lower based on the reserve margins set forth in the Resource Assessment (id. at 58-59). He asserted that, assuming the reference load case and rounding, the Resource Assessment targets reserve requirements of 22 percent in 1998, 21 percent from 1991 through 2001, and 20 percent from 2002 through 2007 (id., citing, Exh. SCE-RR-6S at 13 and n.1). He added that the Resource Assessment specifies even lower reserve margins when higher loads are assumed (id., citing, SCE-RR-6S at 13).[72]

iii. Analysis

As noted above, the Company presented a base supply forecast based on the 1992 CELT report, a high supply forecast based on possible implementation of supply options listed in the 1992 CELT report, and a low supply forecast, based on possible losses of committed capacity included in the base case.[73] The Company characterized the base supply forecast as

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71 The Attorney General indicated that SCE based its reserve margin requirement on the "1989 Annual Review of NEPOOL Required Reserves and Objective Capability for Power Years 1989/90 through 1993/4" (Attorney General Supplemental Brief at 57 through 58, citing, Tr. JH4, at 149). He maintained that this document indicates that required reserves of 20 percent should be increased by only 1.7 percent when the operation of Seabrook reaches maturity, and that Seabrook has been in operation for five years (id., citing, Exh. EFSC-N-3; Tr. JH4, at 149). He stated that the lower reserve margins would, therefore, be appropriate within five years of the June 1990 start date of Seabrook (Attorney General Supplemental Brief at 57 through 58, citing, Exh. EFSC-N-3; Tr. JH4, at 146).

72 The Siting Board notes that within the Resource Assessment, NEPOOL targeted adjusted required reserve requirements to meet the reliability criterion for the high, reference and low loads ranged from: (1) 21 percent to 22 percent for 1998; (2) 20 percent to 22 percent for 1999; (3) 20 percent to 21 percent for 2000 (Exh. SCE-RR-6S, Table 3). The Siting Board further notes that higher reserve requirements were required for lower loads (id.).

73 The Company did not update its analysis of need based on the GNP, linear regression and CAGR regression forecasts to reflect the 1992 CELT Report Forecast (Exh. EFSC-N-48). The 1992 CELT Report supply forecast shows the following differences
(continued...)

the most likely forecast of energy resources available to meet regional need, and the high and low supply forecasts as representative of a reasonable range of supplies, given the uncertainties in potential supply resources. The Attorney General, on the other hand, argued that each of the three supply scenarios understate supply.

With respect to the base supply case, the Attorney General raised concerns regarding the exclusion of (1) the extension of the Hydro-Quebec contract, and (2) both the committed and uncommitted capacity of NUG projects that are existing or under construction. The Siting Board notes that the base supply case, which reflects the committed resources included in the 1992 CELT report, represents the existing energy resources likely to be available to meet the needs of the region over the forecast period. As such, it is reasonable that the base supply case does not assume extension of existing contracts that are due to expire or life extension of existing facilities that are due for retirement during the forecast period. Thus, the exclusion of the extension of the Hydro-Quebec contract from the base supply case is consistent with the resources assumed by NEPOOL over the forecast period, as well as the Company's consideration of various other existing resources that are not planned to continue throughout the forecast period. Therefore, the Siting Board agrees with the Company that the extension of the Hydro-Quebec contract is appropriately included in the high supply case rather than the base supply case.[74]

With respect to NUG projects that are existing or under construction, the Siting Board agrees with the Attorney General that the committed capacity of such NUG projects should be

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[73](…continued)
from the 1991 CELT Report supply forecast: (1) a decrease of 49 MW in 1997; (2) an increase of 13 MW in 1998; (3) an increase of 68 MW in 1999; and (4) an increase of 252 MW in 2000 (Exhs. SCE-9, attached exhibit 3; EFSC-N-62).

[74] The Siting Board notes that even if the extension of the Hydro-Quebec contract were included in the base supply case, it would only affect supply in the years 2001 and beyond.

included in the Company's supply cases.[75] However, the Siting Board disagrees with the Attorney General that the uncommitted capacity of such NUG projects also should be included in the base supply case.[76] The consideration of the uncommitted capacity of these NUG projects is akin to the consideration of existing but uncommitted utility-owned capacity, such as the extension of the Hydro-Quebec contract, other contracts due to expire, or life extensions for existing generating units planned for retirement during the forecast period. Although the infrastructure is in place such that the above capacity could be available, the availability of capacity is not certain over the forecast period. Thus, the uncommitted capacity of NUG projects that are existing or under construction would be appropriate for the high supply case rather than the base supply case. Accordingly, the Siting Board finds that the base supply case, including 83 MW of the committed capacity of NUG projects that are existing or under construction, represents a reasonable base supply forecast for the purposes of this review.

The Siting Board also disagrees with the Attorney General that the low supply case inappropriately overlaps two contingency cases that reflect attrition of utility units. As discussed below, the contingency analysis serves a different purpose than the high and low supply cases. Even if there is some overlap, it is still appropriate to consider a likely change in supply resources, such as the loss of a nuclear unit, as a low supply case. While the Company might have considered discounting the incremental loss of nuclear capacity to reflect the uncertainty of such loss, use of 100 percent of that capacity is not unreasonable given that the reduction is representative of the unavailability of any one of a number of similarly sized resources. Thus, the low supply case represents a reasonable low range of supply likely to be available over the forecast period. Accordingly, the Siting Board finds that the low supply

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75 As noted below, the Company amended the Massachusetts supply forecast to include the committed capacity of Enron because it was under construction. We have assumed that a comparable correction is reasonable to include in the regional need analysis. See Section II.A.4.c., below.

76 The uncommitted capacity of NUG projects that are existing or under construction includes 3 MW for MASSPOWER and 63 MW for Enron.

case, including 83 MW of the committed capacity of NUG projects that are existing or under construction, represents a reasonable low supply forecast for the purposes of this review.

In addition, the Siting Board disagrees with the Attorney General that the high supply case is pessimistic given that the extension of the Hydro-Quebec contract would not affect supply until the year 2001 and only 50 percent of planned utility additions is included. With regard to the first year of the inclusion of the Hydro-Quebec contract, the Siting Board disagrees with the AG that this results in a pessimistic case as lead time is required for any supply addition. The Siting Board also recognizes that the 1992 CELT report includes planned on-line dates for planned utility additions that clearly are uncertain, for example the January, 1996 on-line date for the Edgar Energy Park. A 50 percent success rate for planned utility additions is reasonable, given the uncertainties as to whether, and of equally critical concern when, such facilities may come on line. However, as noted above, the high supply case should be adjusted by 66 MW to account for the uncommitted capacity of NUG projects that are existing or under construction. Thus, as adjusted, the high supply case represents a reasonable high range of supply likely to be available over the forecast period. Accordingly, the Siting Board finds that the high supply case, including 83 MW of the committed capacity of NUG projects that are existing or under construction, and as adjusted by 66 MW of the uncommitted capacity of NUG projects that are existing or under construction, represents a reasonable high supply forecast for the purposes of this review.

With respect to the Company's analysis of supply contingencies, the Siting Board notes that a presentation of supply forecasts based on a selection of such contingencies provides a means to assess the plausible range of variability in future supply. However, in recent decisions, the Siting Board stated its concern with compilations of contingency case capacity position results, stating that such compilations represent a weight-of-the-scenario approach without any explicit analysis of the relative probabilities of the scenarios.[77] Cabot Power

[77] SCE developed scaled estimates of the relative probabilities of its supply forecast and contingency case outcomes, providing a possibly more reliable basis for the Siting (continued…)

Decision, 2 DOMSB at 314-315; Altresco Lynn Decision, 2 DOMSB at 87; EEC (remand) Decision, 1 DOMSB at 458.

With respect to the Attorney General's argument that the Company incorrectly excluded or understated planned but uncommitted NUG capacity from its contingency cases, the Siting Board notes that SCE provided three contingencies covering a range of NUG success rates. While it is appropriate to include a range of potential regional supply scenarios in a contingency analysis, an applicant is not required to consider every possible regional supply outcome that could occur over the forecast period. See, EEC (remand) Decision, 1 DOMSB at 458.

Accordingly, for the purposes of this review, the Siting Board finds that the Company's regional supply contingency analysis provides an acceptable basis for assessing the potential range of regional capacity positions that might arise over the forecast period.

Finally, with respect to the reserve margin, the Siting Board agrees with the Attorney General that the reserve margin assumed by the Company for supply forecasts including the Seabrook unit, 22.5 percent over the forecast period, is too high, given NEPOOL's expectations concerning long-term reserve margins. We note that the Company also acknowledges that it would be reasonable to decrease the reserve margin slightly below 22.5 percent if Seabrook reaches a mature level of operation.

With respect to NEPOOL expectations, the Resource Assessment projects a downward trend in the reserve margin required to meet its reliability criterion. The midpoint of NEPOOL's target reserve margins to meet its reliability criterion for high, low and reference demand forecasts, after 1997, is: (1) 21.5 percent for 1998; (2) 21 percent for 1999; and

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[77](…continued)
Board's consideration of likely forecast variability. In reviewing similar analyses in the Cabot Power Decision, 2 DOMSB at 314-315; Altresco-Lynn Decision, 2 DOMSB at 87-88, however, the Siting Board stated that providing estimated probabilities for an earlier selection of supply forecasts and contingency cases does not necessarily constitute a full and balanced representation, in probabilistic terms, of the actual range of possible outcomes.

(3) 20.5 percent for 2000. The Siting Board also notes that, given the downward trend in NEPOOL-assumed reserve margin requirements, it also would be reasonable to assume a decline from the Company's assumed 22.5 percent reserve margin beginning in 1997. Therefore, based on the foregoing, for the purposes of this review, the Siting Board finds that the Company's reserve margin for supply forecasts including the Seabrook unit in the years 1997 through 2000 should be adjusted as follows: (1) 22 percent for 1997; (2) 21.5 percent for 1998; (3) 21 percent for 1999; and (4) 20.5 percent for 2000.[78]

e. Need Forecasts

i. Description

The Company developed 36 need forecasts based on a comparison of its 12 demand forecasts -- the reference, GNP, linear regression and CAGR regression forecasts and adjustment of each by high and low DSM forecasts -- all compared to three supply forecasts -- base, high and low (Exhs. EFSC-N-48, EFSC-N-62). In comparing the Company's demand and supply forecasts, the cumulative number and percentage of need forecasts that demonstrate a need for at least 150 MW of capacity in the early years of proposed project operation is: (1) 27 need forecast scenarios, 75.0 percent, in 1997; (2) 33 need forecast scenarios, 91.7 percent, in 1998; (3) 34 need forecast scenarios, 94.4 percent in 1999; and (4) 36 need forecast scenarios, 100 percent, in 2000 and beyond (id.). See Table 1. The Company indicated that comparison of the GNP forecast with the base supply forecast showed a need for over 150 MW in the early years of the proposed project, specifically: (1) 2,199 MW in 1997; (2) 3,153 MW in 1998; (3) 4,033 MW in 1999; and (4) 5,082 MW in 2000 (id.). See Table 1.

SCE then subjected each of the 36 need forecasts to up to 16 contingency adjustments which would increase or decrease supply, generating 420 contingency cases (Exhs. SCE-9, attached exhibits 5 through 11, EFSC-N-48, EFSC-N-62). A summary of the regional need cases indicates that the cumulative number and percentage that demonstrate a need for at least

[78] As noted above, the low supply forecast excludes the Seabrook unit and therefore assumes use of a reserve margin of 20 percent. See Section II.A.3.d.i.(B), above.

150 MW are: (1) 370 need cases, 81.1 percent, in 1997; (2) 418 need cases, 91.7 percent, in 1998; (3) 437 need cases, 95.8 percent, in 1999; and (4) 451 need cases, 98.9 percent in 2000 (id.).

ii. Positions of the Intervenors and the Company's Response

The Attorney General argued that evaluation of the need for a proposed facility by the mere multiplication of need scenarios is meaningless where the supply scenarios do not reflect neutral selection criterion and overlap with each other (Attorney General Brief at 78; Attorney General Supplemental Brief at 61 through 65).

In addition, the Attorney General argued that the need for the proposed project should not be based on a time frame later than the first year that the proposed project would be on-line (Attorney General Supplemental Brief at 14, 15)). The Attorney General stated that the Siting Board has never approved a non-utility power project that is not likely to be needed its first year of operation (id.). Here, he argued, the Company is suggesting that the Siting Board find need if the project is needed at any time within five years of initial operation (id.).

The Company responded that the Siting Council never determined that it would be inappropriate to consider the need for a proposed facility beyond the first year of operation and that, in fact, the Siting Council, in two previous reviews of NUG projects, considered need in years beyond the first year of proposed facility operation (SCE Reply Brief, n.3, citing, West Lynn Decision, 22 DOMSC at 11-36, Enron Decision, 23 DOMSC at 49). The Company asserted that, given the uncertainties regarding load growth and in-service date of a generating facility, it is appropriate to consider the need for a project beyond the first year of operation (id.).

iii. Analysis

As an intial matter, in regard to the time period of our need review, the Siting Board notes that it is appropriate to consider need within a time frame beyond the first year of planned facility operation and we have previously considered capacity position beyond the first year of proposed facility operation as part of assessing need for reliability purposes in reviews of NUG projects. See, Cabot Power Decision, 2 DOMSB at 289-290; Altresco Lynn Decision, 2 DOMSB at 58-59; EEC (remand) Decision, 1 DOMSB at 463-464; West Lynn Decision, 22 DOMSC at 14, 33-34. 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.[79] Thus, for the purposes of this review, the Siting Board finds that it is appropriate to explicitly consider need for the proposed facility within the 1997 to 2000 time period.

As noted above, in considering the Company's demand and supply forecasts, the Siting Board has adjusted: (1) all supply forecasts to reflect the 1992 CELT Report supply assumptions with the addition of 83 MW for the committed capacity of the Enron facility; (2) the 1992 CELT DSM levels by 11.4 percent of the increment over 1991 levels in the reference forecast base DSM case; (3) the Company's high supply forecast by 66 MW to include the uncommitted capacity of NUG projects that are existing or under construction; and (4) the Company's assumed reserve margin of 22 percent to reflect lower levels after 1997, specifically 21.5 percent for 1998, 21 percent for 1999, and 20 percent for 2000.[80]

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79 As explained above, an analysis of capacity position is not the only basis by which a facility proponent can establish need. Instead, need also can be established by a combination of factors related to the energy supply. See Section II.A.1.c., above.

80 The Company's need forecasts incorporating the three alternative demand forecast methodologies were based on the 1991 CELT Report supply forecast. To adjust those need forecasts to reflect the 1992 CELT Report supply forecast, the following supply changes are appropriate: (1) a decrease of 49 MW in 1997; (2) an increase of 13 MW in 1998; (3) an increase of 68 MW in 1999; (4) an increase of 252 MW in 2000 (Exhs. SCE-9, attached exhibit 3; EFSC-N-62). In addition, the Company recalculated its Massachusetts need forecasts to include the committed capacity of the Enron facility, and thus it is appropriate to include the 83 MW of committed capacity of the Enron

(continued...)

With respect to the Company's demand forecasts, the Siting Board has found that; (1) the reference forecast is an appropriate base case forecast for use in an analysis of regional demand for the years 1996 through 2007; (2) the GNP, linear regression, and CAGR regression forecasts provide alternative forecasts, with the caveats as noted above.

While accepting the GNP, linear regression, and CAGR regression, forecasts for use in an analysis of regional demand, the Siting Board identified concerns with these approaches. The identified concerns affect the weight the Siting Board places on these forecasts. As a result, for purposes of this review, the Siting Board places more weight on the reference forecast. Accordingly, the Siting Board addresses need based on two compilations of the Company's need forecasts as adjusted (1) a compilation including only those need forecasts incorporating the reference forecast, and (2) an overall compilation including all 36 need forecasts reflecting all four demand forecast methodologies.[81]

Separating out the forecast methodologies as described above, the number of need forecasts that demonstrate a need for at least 150 MW in each year, from 1997 through 2000, is as follows:

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[80](…continued)
facility in the regional need forecasts discussed in this section. However, although the Company also recalculated its Massachusetts need forecasts to correct the level of purchases from PASNY, there is no indication whether the correction reflects a change in overall purchases or in the allocation of purchases to Massachusetts (see Section II.A.3.d.i.(A), above). Thus, in analyzing the Company's need forecasts in this section, the base, high and low supply forecasts were increased to reflect the update of the 1991 CELT Report supply forecast by the 1992 CELT Report supply forecast, and to include the committed portion of the Enron facility.

[81] As indicated in Section II.A.3.d.iii, above, the Siting Board does not further consider SCE's contingency cases, given their reflection of a weight-of-the-scenario approach.

Forecast	1997	1998	1999	2000
Reference forecast (9 cases)	0 (0%)	1 (11%)	5 (56%)	6 (67%)
Alternative forecasts (27 cases)	25 (93%)	27 (100%)	27 (100%)	27 (100%)
Total (36 cases)	25 (69%)	28 (78%)	32 (89%)	33 (92%)

The capacity positions under the need forecasts, as adjusted, are shown in Table 2. Considered with the base DSM forecast, and the base supply forecast: (1) the reference forecast shows a need for 553 MW in 2000; (2) the GNP forecast shows a need for 2,046 MW in 1997; (3) the linear regression forecast shows a need for 950 MW in 1997; and (4) the CAGR regression forecast shows a need for 2,712 MW in 1997.

In sum, of the Company's 36 total need forecasts, 25 show a need for at least 150 MW in 1997, 28 show a need for at least 150 MW in 1998, 32 show a need for 150 MW in 1999, and 33 show a need for 150 MW in 2000. However, none of the nine need forecasts that incorporate the reference forecast show a need for at least 150 MW in 1997, one such forecast shows a need for at least 150 MW in 1998, five such forecasts show a need for at least 150 MW in 1999, and six such forecasts show a need for at least 150 MW in 2000.

Accordingly, giving added weight to the need forecasts based on the reference forecast for the reasons noted above, based on the foregoing, the Siting Board finds that there will be a need for 150 MW or more of additional energy resources in New England for reliability purposes beginning in 2000 and beyond.

f. Economic Efficiency

i. Description

SCE argued that the proposed facility would produce significant economic efficiency benefits for the region under a range of load growth and fuel price scenarios (SCE Brief at 74 through 80). The Company indicated that inclusion of the TEC in the NEPOOL dispatch pool would result in a net reduction in total electric costs to the region as a result of (1) variable (i.e., energy) cost savings of existing and future additional energy resources,[82] and (2) the avoided cost savings of future additional energy resources (i.e., capital and operations and maintenance ("O&M") costs) (Exh. SCE-9, at 13).

In support, SCE provided a series of detailed economic analyses with and without the proposed facility based on NEPOOL dispatch practices with projected generation expansion reflecting a mix of oil-fired gas turbines, gas-fired combined cycle units with oil back-up, and CFB coal units (Exhs. SCE-9, at 12 through 19 and exh. 12, exh. 13, exh. 14; EFSC-RR-120).[83,84] SCE modelled the NEPOOL dispatch order[85] over the twenty-year period,

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82 The Company indicated that the proposed project would replace existing units with higher energy costs (Exh. SCE-1, at 4-40). In addition, SCE indicated that the proportionate increase in coal-fired energy within NEPOOL would reduce the average fossil fuel cost for NEPOOL as a whole, thereby reducing the price of purchased power where individual contracts are tied to NEPOOL's fossil fuel index (id.).

83 SCE assumed that: (1) the oil-fired gas turbine units would be peaking resources; (2) the gas-fired combined cycle units would be base and/or intermediate resources; and (3) the CFB coal units would be base resources (Exh. SCE-9, at 13).

84 SCE indicated that its model produced the generation expansion plan mix, which, together with existing NEPOOL resources, would result in the lowest total cost for power (Exh. SCE-9, at 13). SCE stated that most assumptions for the generic future units, including capital costs, O&M costs, and operating parameters, were taken from the 1989 Electric Power Research Institute ("EPRI") Technical Assessment Guide ("TAG") (Exhs. SCE-9, at 14 through 15; SCE-1, at 5-12 through 5-14). SCE added that fuel price forecasts were consistent with the December 1988 Energy Modeling Forum ("EM Forum") fuel escalation forecasts and that the generic gas-fired combined cycle units were assumed to utilize gas for 305 days and oil for 60 days during the winter (Exhs. SCE-9, at 13 through 14; AG-RR-39).

85 The Company indicated that it assumed existing and committed resources consistent

(continued…)

1996 through 2015,[86] assuming various load growth and fuel price forecasts (Exh. SCE-9, at 12 through 19 and exh. 12, exh. 13).[87] Specifically, the Company provided ten alternative scenarios of regional cost savings based on four alternative load forecast methodologies -- linear, 1990 CELT, GNP and CAGR -- and four fuel price forecasts based on a study by the EM Forum (id.).[88,89] The Company stated that these analyses demonstrate that the proposed project would provide regional economic efficiency savings in 1991 dollars ranging from $56

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[85](…continued) with the base supply case from its regional analysis, based on the 1991 CELT Report (Exh. SCE-9, at 9,15). The Company further indicated that fuel price estimates were consistent with the EM Forum fuel escalation forecasts and that the energy cost corresponding to each generating resource was based on estimates of the units' full-load heat rate and respective fuel cost (id. at 13 through 14). The Company assumed that dual-fuel units would utilize natural gas for 305 days and oil for 60 days, that unit availability factors would be consistent with corresponding NEPOOL estimates of "target unit availability," and that reserve margins would be 22.5 percent of the projected peak demand for each year (id.).

86 SCE provided an initial economic efficiency analysis for the 20-year period beginning in 1995 but then updated its analysis based on the 20-year period beginning in 1996 to correspond to an anticipated 1996 on-line date (Exhs. SCE-9, at 12 through 19; EFSC-RR-120). In updating the analysis, the Company assumed the net present value savings for the year 2015 would equal the savings determined for the year 2014 (Exh. EFSC-RR-120).

87 SCE assumed that (1) the proposed project as well as all gas-fired, existing and/or committed NUGs would be dispatched on an economic basis, and (2) all existing and/or committed NUGs not fueled by natural gas would be "must-run," and, therefore, dispatched ahead of the proposed project (Exh. SCE-9, at 14).

88 SCE indicated that the EM Forum developed fuel price forecasts based on four different sets of assumptions: (1) high oil prices; (2) low oil prices; (3) low domestic gas resources; and (4) high domestic gas demand (Exh. SCE-1, at 5-14).

89 The Company provided (1) eight scenarios based on the combination of each of the four load forecasts with the two fuel price forecasts based on high oil prices and low oil prices, and (2) two scenarios based on the combination of the 1990 CELT forecast with the two fuel price forecasts based on low domestic gas resources and high domestic gas demand (Exh. SCE-9, at 12 through 19 and exh. 12, exh. 13).

million dollars to $107 million dollars over the 20-year period, with the greater load growth and oil price forecasts producing the higher-end savings (Exh. EFSC-RR-120).[90]

During the course of the proceeding, the Company provided three additional scenarios of regional cost savings based on (1) an alternative lower oil fuel forecast[91] combined with both the linear demand forecast and the 1991 CELT forecast,[92] and (2) the 1991 CELT fuel forecast combined with the 1991 CELT demand forecast (Exh. EFSC-RR-120; Tr. 15, at 46 through 50). SCE indicated that the additional scenarios demonstrate that the proposed project would provide present value savings in 1991 dollars (1) ranging from $39 million to $95 million for the analyses based on the 1991 CELT forecast, and (2) $47 million for the analysis based on the linear demand forecast (Exh. EFSC-RR-120).[93]

With respect to the cost impact of the proposed project for the years 1996 through 1999, the Company's analysis indicates that for scenarios based on the 1990 CELT demand forecast, dispatch of the proposed project would result in increased fixed costs but decreased

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90 The Company indicated that given that TMLP has contracted for 30 MW or approximately 20 percent of the output of the proposed project, 20 percent of the savings attributable to the proposed project would directly benefit Massachusetts (Exh. SCE-9, at 19). The Company added that benefits to Massachusetts would increase based on the percentage of remaining capacity that is sold to Massachusetts utilities (id.).

91 The alternative lower oil price forecast was based on the EM Forum lower oil price forecast with an alternative escalation forecast for number 6 oil (Exh. EFSC-RR-120).

92 SCE asserted that, although the low load growth exhibited by the 1991 CELT forecast would be inconsistent with the alternative lower oil fuel forecast, under these assumptions the proposed project would still produce net present value savings of $39 million (SEC Brief at n.8, citing, Exh. EFSC-RR-120).

93 The Company also provided a fuel diversity analysis, comparable to the economic efficiency analysis, that excluded generic CFB coal units from generation expansion, and assumed the 1990 CELT load forecast and both the high oil price and low oil price fuel forecasts (Exh. SCE-9, at 17 through 19). The Company stated that such analysis would identify the savings attributable solely to the proposed project (id.).

variable costs within NEPOOL in each year under all fuel price forecasts (Exh. SCE-9, exh. 13). However, the proposed project would result in an increase in combined fixed and variable costs to NEPOOL under the lower oil price forecast for the years 1996 through 1998, no change to NEPOOL costs for the year 1999, and savings to NEPOOL for the year 2000 (id.). Under all other fuel price forecasts, the proposed project would result in savings to NEPOOL for each year (id.).[94] For scenarios based on the 1991 CELT demand forecast, dispatch of the proposed project also would result in increased fixed costs and decreased variable costs within NEPOOL but, overall, would result in increased costs to NEPOOL for each year 1996 through 2000, and savings to NEPOOL for each year following 2000, under both fuel price forecasts (Exh. EFSC-RR-120).[95]

ii. Position of the Attorney General and the Company's Response

The Attorney General argued that the Company's economic efficiency analysis does not provide a reliable basis for determining need and should be rejected (Attorney General Brief at 119 through 133). In support, the Attorney General argued that the economic efficiency analysis was not based on the 1992 CELT forecast but, instead, was based on

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94 The total yearly impact would range from: (1) costs of $5 million to savings of $7 million for 1996; (2) costs of $4 million to savings of $9 million for 1997; (3) costs of $1 million to savings of $8 million for 1998; and (4) no impact to savings of $10 million for 1999 (Exh. SCE-9, exh. 13).

95 The total yearly impact would range from costs of: (1) $19 to $22 million for 1996; (2) $14 million to $18 million for 1997; (3) $11 million to $15 million for 1998; (4) $7 million to $12 million for 1999 (Exh. HO-RR-120).

outdated and unreliable load forecasts,[96] and, in addition, was based on cost assumptions that biased the analysis in favor of the proposed project (id. at 126 through 132).

The Attorney General took issue with the Company's cost assumptions relative to: (1) the cost of the proposed project; (2) the fuel costs for other units; and (3) the cost of future resource additions (id.). The Attorney General stated that costs of the proposed project were based on the TMLP contract and, as such, likely were understated given that (1) only 20 percent of the power of the proposed project is sold, and (2) costs have increased since the power was sold (id. at 127 through 128).[97] The Attorney General also stated that SCE's use of the EM Forum fuel price forecast to project costs of other NEPOOL units was unwarranted, given that the EM Forum fuel price forecast was outdated and was not developed to forecast prices of specific fuels in New England (id. at 128-131).[98] The Attorney General noted that the EM Forum fuel price forecast is higher than the 1991 CELT Report fuel price forecast which was criticized by the Company as too high, and that the fuel price assumptions of the 1992

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96 The Attorney General argued that the economic efficiency analysis based on the 1991 CELT report and the alternative lower fuel forecast is the most dependable forecast and demonstrates savings of only $6 million over a 20-year period, insufficient to justify construction of the proposed facility (Attorney General Brief at 126 through 127, citing, EFSC-RR-120). The Attorney General added that the economic efficiency analysis which the Company stated was based on the 1991 CELT forecast and 1991 CELT fuel forecast should be disregarded because the fuel forecast utilized by the Company does not correspond to the fuel forecast utilized in the 1991 CELT Report (id. at n.30).

97 In addition, the Attorney General argued that SCE did not take into account expected increases in costs due to the one year delay in the on-line date of the proposed project (Attorney General Brief at 127, citing, Tr. 21, at 87 through 89). The Siting Board notes that it is extremely unlikely that the project could be on-line prior to 1998 based on current permitting and power sales status.

98 The Attorney General stated that the EM Forum fuel price forecast was developed during the 1986 to 1988 timeframe to predict the effects of changes in oil prices, gas demand and gas availability on the United Stated and Canadian gas markets and had not been updated to reflect current market conditions (Attorney General Brief at 128 through 131, citing, Tr. 15, at 30 through 32; Tr. 21, at 45).

CELT Report declined relative to those of the 1991 CELT Report (id. at 131). The Attorney General further stated that generic facility costs likely are higher than actual facility costs and that, therefore, costs of the future resource additions which were based on generic cost assumptions rather than actual PPAs, are likely overstated (id. at 132). The Attorney General added that the Company's cost estimate for future combined cycle units did not take into account technology advances that would likely decrease costs of plants built ten years from now (Attorney General Reply Brief at 17 through 18).[99]

The Attorney General also argued that the Company's own economic efficiency analyses demonstrate uncertain results (Attorney General Reply Brief at 10 through 12). The Attorney General stated that, under the low oil price scenarios, the Company's analyses do not predict savings from the operation of the proposed facility until 2007 and that savings are further delayed under scenarios that incorporate the 1991 CELT forecast (id. at 11, citing, Exhs. SCE-9, exh. 13; EFSC-RR-120). The Attorney General added that such delay renders the magnitude of savings uncertain given that alternative, lower-cost resource options are likely to be available by 2007 and that load forecasts are more uncertain in the later years (id.).

In response to the Attorney General's criticism of the age of the underlying forecast in the Company's analysis, the Company further stated that an economic efficiency analysis based on the 1992 CELT report was not requested by the Siting Board Staff (SCE Reply Brief at 41). However, the Company added that a reasonable starting point for a comparison with an analysis based on the 1992 CELT report would be the analysis based on the 1991 CELT report and adjusted lower oil fuel forecast which demonstrated savings of $39 million over the twenty

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99 The Attorney General also stated that, in its dispatch of future resources, SCE failed to consider possibilities that could potentially offer power at a lower cost than the proposed project, including: (1) the retrofitting or life-extension of existing plants; (2) conversion of oil-fired facilities to gas; and (3) conservation (Attorney General Brief at 132, citing, Tr. 13, at 47 through 48).

year period (id. at 41).[100] With regard to the Attorney General's criticism of the fuel price forecasts utilized in the Company's analyses, SCE stated that the EM Forum fuel price forecasts provide a broad bandwidth of fuel prices and that the Company provided analyses based on additional fuel price forecasts including forecasts consistent with the 1991 CELT Report fuel prices (id. at 42-44). Finally, with regard to the Attorney General's criticism of TEC's capital costs, the Company stated that such costs were correctly based on the fixed costs contained in the TMLP contract and are consistent with bids to other utilities (id. at 47).

The Attorney General also provided independent analyses of the economic impact of dispatch of the proposed project prepared by Dr. Shakow, based on PURLE model simulations of dispatch with and without the proposed project (Exhs. SCE-RR-2; SCE-RR-3; EFSC-RR-124; EFSC-N-66).[101,102] The Attorney General argued that, although certain assumptions were biased in favor of the proposed project,[103] the analyses demonstrated that, under a variety of

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100 SCE stated that an analysis based on the 1992 CELT report would reflect greater savings because: (1) the 1991 CELT forecast is substantially lower than the 1992 CELT forecast; (2) oil price projections are lower than those used in the 1992 CELT report for all but the first three years; and (3) the projected energy costs for the proposed facility would be higher under the 1991 CELT report than under the 1992 CELT report because fuel cost escalators for the proposed facility were based on the GNP (SCE Reply Brief at 42).

101 As noted above, Dr. Shakow considered the PURLE model, which includes a load forecasting module, a resource selection module and a dynamic least-cost expansion module, to be a diagnostic model rather than a full-scale utility planning program model (see Section II.A.3.b.ii, above) (Exh. AG-1, at 55 through 56; Tr. 25, at 33).

102 The Siting Board focuses on the more recent economic efficiency analyses provided by the Attorney General (Exhs. EFSC-N-66; SCE-RR-2; SCE-RR-3; EFSC-RR-124). The Attorney General indicated that said analyses assumed: (1) a 26-year timeframe; (2) TEC project costs consistent with the TMLP contract; and (3) PURLE-generated load forecasts based on various CELT inputs (id.).

103 The Attorney General argued that assumptions which were biased in favor of the proposed project include: (1) a 26-year timeframe; (2) the inclusion of no new facilities, other than the proposed project; and (3) the adoption of project costs reflected

(continued…)

future load growth, economic growth, fuel cost and electricity cost scenarios, the savings associated with the proposed project do not match its costs (Attorney General Brief at 121 through 125). The Attorney General also argued that Dr. Shakow correctly excluded the capital costs of generic future additions in his economic efficiency analysis and noted that, at most, such costs should not be included until the year that the additional generic unit would be needed (Attorney General Reply Brief at 15 through 16).

The Company questioned the overall validity of the economic efficiency analyses provided by the Attorney General and asserted that said analyses should be rejected by the Siting Board (SCE Brief at 80 through 93). In support, the Company stated that the model utilized by Dr. Shakow -- the PURLE model -- was relatively unknown, untested and not intended for planning purposes (SCE Brief at 81 through 82).[104] In addition, the Company stated that the results of Dr. Shakow's economic efficiency analyses were biased against the proposed project due to: (1) errors in input data including load shape projections and Hydro-Quebec capacity;[105] (2) the use of unreasonably low PURLE-based load forecasts; (3) the

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[103](…continued)
in the current contract with TMLP (Attorney General Brief at 121 through 123).

[104] The Company stated that, in contrast, its own model was widely utilized within the industry to project generation expansion (SCE Brief at 81).

[105] The Company stated that, consistent with historic NEPOOL data, Mr. Booth assumed a minimum load to peak load ratio of 35 percent while Dr. Shakow assumed a ratio of 50 percent reflecting a flatter load shape (SCE Brief at 82 through 84). The Company stated that under Dr. Shakow's assumption, a greater portion of demand would be met by base load units rather than more costly peaking and intermediate units, thus understating the cost savings of a new unit such as the proposed project (id.). The Attorney General responded that peak load management would flatten the future load shape consistent with Dr. Shakow's assumptions (Attorney General Reply Brief at 20).

The Company also stated that Dr. Shakow overstated the capacity of Hydro-Quebec, and, therefore, understated costs savings due to the proposed project given that Hydro-Quebec is a large base-load resource, less costly than many other NEPOOL resources

(continued…)

assumption of a 1995 in-service date; and (4) the omission of capital costs of new units in all dispatch scenarios that do not include the proposed project (id. at 80 through 93).[106,107]

iii. Analysis

In the past, the Siting Council determined that, in some instances, utilities need to add energy resources primarily for economic efficiency purposes. Specifically, in the 1985 MECo/NEP Decision, 13 DOMSC at 178-179, 183, 187, 246-247, and Boston Gas Company, 11 DOMSC 159, 166-168 (1984), the Siting Council 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 Council standard indicated that need may be established on either reliability or economic efficiency grounds. Enron Decision, 23 DOMSC at 55-56; EEC Decision, 22 DOMSC at 207-241; NEA Decision, 16 DOMSC at 344-360.

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

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[105](…continued)
(SCE Brief at 84). The Attorney General responded that Dr. Shakow assumed Hydro-Quebec capacity consistent with Company assumptions (Attorney General Brief at 21).

[106] SCE stated that the reason that NUGs can provide power at less than a utility's avoided cost is that both variable and capacity costs are avoided by the new unit and that failure to include avoided capacity costs understates avoided costs and economic efficiency benefits (SCE Reply Brief at 49).

[107] SCE stated that the analysis based on the 1992 CELT load forecast was further flawed by use of fuel price assumptions from the 1992 GTF Report rather than the higher fuel price assumptions incorporated in the 1992 CELT reference forecast (SCE Brief at 92).

Decision, 2 DOMSB at 292-296; Altresco Lynn Decision, 2 DOMSB at 61-65; Enron Decision, 23 DOMSC at 49-55; MASSPOWER Decision, 20 DOMSC at 323.

In the MASSPOWER Decision, 20 DOMSC at 323; the West Lynn Decision, 22 DOMSC at 36; and the EEC Decision, 22 DOMSC at 241; the Siting Council rejected the Companies' arguments, finding problems with elements of their analyses. In those decisions the Siting Council noted that proponents must provide adequate analyses and documentation in support of assertions that their respective projects are needed on economic efficiency grounds.

In the Enron Decision, for the first time, the Siting Council found that a non-utility generating project was needed for economic efficiency purposes. 23 DOMSC at 55-62. The Siting Council noted that such a finding, based on comprehensive analyses of NEPOOL dispatch both with and without a proposed project, is necessarily project-specific. Id. at 58. The Siting Council indicated that since, unlike economic efficiency gains associated with specific PPAs, regional economic efficiency gains are not contractually guaranteed, the degree to which they are assured would be a critical factor in our evaluation of regional need for economic efficiency purposes. Id. at 58-59. The Siting Council also identified the magnitude and timing of such gains as critical to our review. Id. at 59.

In the two most recent reviews of generating facilities with expected on-line dates prior to 2000, proponents have provided analyses showing their projects would generate significant and quantifiable savings to the region over 19 to 20 years, under a range of assumptions regarding potential load growth, fuel prices, avoided capacity costs, and types of future generation built in the region. Cabot Power Decision, 2 DOMSB at 298; Altresco Lynn Decision, 2 DOMSB at 66-67. However, in focusing on the savings under the base case forecast accepted by the Siting Board to establish the first year of reliability need in those reviews -- the year 2000 -- the Siting Board recognized that the proponents had not demonstrated a need for the proposed project in the years prior to 2000, based on economic efficiency. Cabot Power Decision, 2 DOMSB at 298; Altresco Lynn Decision, 2 DOMSB at 68. Specifically, the Siting Board recognized that the proponents' analyses not only showed mixed results under the base demand forecast for the years prior to 2000, but also overstated the savings for such years by including avoided capacity costs when in fact it was unclear whether additional capacity would be needed. Cabot Power Decision, 2 DOMSB at 299; Altresco Lynn Decision, 2 DOMSB at 67-68. However, the Siting Board found that the proponents in those cases had established that the region would need additional energy resources from the proposed projects for economic efficiency purposes beginning in the 2000 timeframe, noting that such finding alone was not sufficient to establish need for a project with an expected on-line date prior to 2000. Cabot Power Decision, 2 DOMSB at 300; Altresco Lynn Decision, 2 DOMSB at 68.

Here, as in previous reviews, the Company has provided an economic efficiency analysis based on a range of demand forecasts and fuel price forecasts showing 20-year net present value ("NPV") savings, but showing mixed results with respect to annual NPV economic efficiency effects in years prior to 2000. Further, as in previous reviews, SCE's calculations reflect avoided capacity costs beginning in 1996, although the capacity is not needed for reliability purposes until 2000.

However, although the economic efficiency analysis was based on a range of load forecasts -- the 1990 CELT forecast, the 1991 CELT forecast, the linear regression forecast, the GNP forecast, and the CAGR regression forecast -- and a range of fuel price forecasts, the Siting Board has concerns regarding the age and reliability of these forecasts. With respect to load forecasts, the Siting Board notes that the 1990 CELT forecast is outdated and the 1991 CELT forecast previously has been rejected by the Siting Council for the purposes of evaluating regional need.[108] Further, although the linear regression, GNP, and CAGR regression forecasts have been accepted as possible forecasts, none of these forecasts has been accepted as a base case forecast for the purposes of establishing regional need on reliability grounds (see Section II.A.3.b.iii., above).

Although the Company argued that the Siting Board did not specifically request an economic efficiency analysis based on the 1992 CELT reference forecast -- the forecast

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108 See, EEC Decision, 20 DOMSC at 235-236; Enron Decision, 23 DOMSC at 42-43.

accepted as a base case forecast in Section II.A.3.b.iii., above -- we note that it is the Company's obligation to provide sufficient documentation to demonstrate the magnitude and timing of economic efficiency benefits. We further note that the Company updated its regional need analysis, of which economic efficiency-based need is part, based on the 1992 CELT Report. At the time of such update, the Siting Council had already rejected the 1991 CELT forecast for the purposes of evaluating regional need in three separate reviews of generating facilities and the 1990 CELT report was already two years old. In addition, while the Company has countered that one economic efficiency analysis, based on the 1991 CELT Report forecast, would represent a reasonable lower bound to the economic efficiency savings that would be realized under the 1992 CELT reference forecast, the Company did not provide supporting documentation.

In addition, although the Company has incorporated a range of alternative fuel price scenarios into its economic efficiency analyses, the Siting Board shares some of the concerns of the Attorney General regarding the age of the fuel price scenarios based on the EM Forum forecasts which were developed during the 1986-1988 time period.

In sum, the Company has provided a detailed description of the methodology and assumptions used in its analyses of economic efficiency savings, including scenarios which incorporate load growth and fuel price uncertainty. The Company's analyses demonstrate potential economic efficiency benefits over a twenty-year timeframe but also show mixed economic efficiency benefits and costs for the years prior to 2000.

However, the Siting Board has clearly stated that a proponent must provide adequate analyses which demonstrate the magnitude and timing of economic efficiency gains. Here, the Company did not provide an economic efficiency analysis which reflects the reference forecast -- the forecast accepted in Section II.A.3.b.iii., above, as an appropriate base case demand forecast in evaluating need for reliability purposes and, as such, has not established the magnitude and timing of potential economic efficiency gains based on acceptable demand and supply assumptions. In addition, the Company's analyses are methodologically flawed in including avoided capacity costs for all years of the analyses, including years in which the

Siting Board found no reliability-based need. Accordingly, based on the record, the Siting Board finds that the Company has not established that New England will need 150 MW of additional energy resources from the proposed project for economic efficiency purposes.

4. Massachusetts' Need

a. Introduction

SCE asserted that there is a need for new capacity in Massachusetts beginning in 1997 or earlier, and continuing beyond 1997 (SCE Supplemental Brief at 36). The Company further asserted that the need for new capacity in Massachusetts arises earlier than the need for new capacity in New England as a whole (id.). To support its assertions, the Company presented a series of forecasts of demand and supply for Massachusetts, based in part on 1992 forecast documents and other data published by NEPOOL and, as necessary, prorated to Massachusetts by the Company (Exh. SCE-22). The Company combined its demand and supply forecasts to provide a series of Massachusetts need forecasts, and also subjected the need forecasts to a variety of contingency tests to evaluate the sensitivity of the need forecasts to the uncertainty inherent in underlying forecast assumptions (id.). In addition, SCE presented analyses of transmission system reliability benefits and environmental benefits associated with the displacement of more polluting generation by the proposed project (Exhs. SCE-1, at 4-45 through 4-47; SCE-9, exh. 15; EFSB-RR-161).

In the following sections, the Siting Board reviews the demand forecasts provided by the Company, including the demand forecast methodologies and estimates of DSM savings over the forecast period, and the supply forecasts provided by the Company, including the capacity assumptions and required reserve margin assumptions. The Siting Board then reviews the need forecasts which are based on a comparison of the various demand and supply forecasts. Finally, the Siting Board reviews the other factors, i.e., transmission system benefits and air quality benefits, analyzed by the Company in support of Massachusetts need for the proposed project.

b. Demand Forecasts

i. Description

The Company presented 11 forecasts of Massachusetts adjusted peak load demand (Exh. SCE-22, at 5-9 and att. RLC-10). The Company stated that it based its Massachusetts demand forecasts on five different demand forecast methodologies and three different forecasts of reductions in peak demand resulting from utility-sponsored DSM programs (id. at 5). To derive its 11 demand forecasts, the Company indicated that it adjusted results from three of its forecast methodologies to reflect the three respective DSM forecasts generating nine distinct forecasts of peak load (id.). The Company utilized results from the remaining two forecast methodologies without separate reductions to reflect DSM (id.).

(A) Demand Forecast Methodologies

The five demand forecast methodologies utilized by the Company included: (1) the NEPOOL 1992-2007 energy and peak load forecast for Massachusetts, a companion forecast to the reference forecast incorporated in the Company's regional need analysis ("Massachusetts reference forecast"); (2) a Massachusetts expected value forecast, derived from the NEPOOL 1993-1997 expected value load forecast presented in the 1992 Resource Assessment ("Massachusetts expected value forecast"); (3) a variation of the Massachusetts reference forecast, based on a constant annual growth rate ("CAGR") projection between 1992, or first year, peak load and 2007, or end year, peak load as forecasted by NEPOOL in the Massachusetts reference forecast ("Massachusetts end year CAGR forecast"); (4) a historical time series linear regression forecast, based on projection of the 1974-1991 linear regression trend over the 1992-2007 forecast period ("Massachusetts linear regression forecast"); and (5) a historical time series CAGR regression forecast, based on projection of the 1974-1991 CAGR regression trend over the 1992-2007 forecast period ("Massachusetts CAGR regression forecast") (id.). The Company stated that its Massachusetts reference forecast was obtained directly from a published NEPOOL source, and the remaining demand forecasts were based on data derived largely from reports published by NEPOOL and its affiliated New England Power Planning Committee (id. at 6 through 7).

The Company indicated that one of its Massachusetts demand forecast methodologies -- the Massachusetts reference forecast -- corresponds to a demand forecast methodology used in the regional need analysis (Exh. EFSB-RR-168). Repeating arguments from its regional need analysis (see Section II.A.3.b.i., above), the Company characterized the Massachusetts reference forecast as a reasonable long-term forecast, but cautioned that the forecast was overly pessimistic in the short term (SCE Supplemental Brief at 21).[109]

With regard to the expected value forecast, SCE first defined the expected value as the mean value of a probability distribution, or the weighted average of all possible outcomes in the distribution (Exh. SCE-RR-6; Tr. JH5 at 60 through 61). The Company indicated that the 1992 NEPOOL Resource Assessment provides a probability distribution for the variation in expected regional load growth assumed by NEPOOL for the years 1993 through 1997,[110] and from this distribution, derives the expected value of the load forecast for each year from 1993 through 1997 (Exh. SCE-RR-6S).[111] SCE indicated that the probability that actual load would be less than or equal to the load predicted by the expected value forecast, that is, the confidence level of the forecast, would vary between 57 percent and 62 percent for the years 1993 through

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109 The Company indicated that its Massachusetts reference forecast reflects an average annual growth rate in adjusted peak load of 2.21 to 2.55 percent over the 1992-2007 forecast period, depending on which of the Company's three DSM forecasts is used (Exh. SCE-22, at att. RLC-10) (see Section II.A.4.b.i.(B), below).

110 SCE indicated that the five drivers to the 1993-1997 load growth forecast were employment, economic output, population, and real prices of electricity and fuels (Tr. JH5, at 53; Exh. SCE-RR-6, at 6).

111 The Company indicated that the Massachusetts expected value forecast exceeded the Massachusetts reference forecast by: (1) 83 MW in 1993; (2) 181 MW in 1994; (3) 312 MW in 1995; (4) 304 MW in 1996; and (5) 407 MW in 1997 (Exh. SCE-22 at att. RLC-10; Tr. JH5, at 40 through 41).

1997 (Exh. SB-JH-RR-8).[112] The Company extrapolated values for the years beyond 1997 based on a linear regression of the NEPOOL forecast data for 1993 through 1997 (id.).

To derive the Massachusetts expected value forecast, the Company stated that it prorated, on a year-to-year basis, the forecasted demand in its regional expected value forecast by the ratio of the forecasted demand in the Massachusetts reference forecast to the forecasted demand in the reference forecast (Exh. SCE-22, at 6). The Company stated that, since the reference forecast and the Massachusetts reference forecast are consistent in terms of methodology and assumptions, it is reasonable to use them for purposes of prorating the expected value forecast (Exh. EFSB-MN-2).

SCE stated that the expected value forecast would represent a reasonable base-case demand forecast (Exh. SCE-22, at 9). In support, the Company asserted that the NEPOOL expected value forecast (1) is the product of a sophisticated methodology, and (2) incorporates a probabilistic approach which is preferable to a deterministic approach because it is inherently

112 Mr. La Capra explained that the expected value forecast would differ from the 50 percent confidence level, which is the basis for the reference forecast, in that the 50 percent confidence level represents a median while the expected value represents the average of a range of outcomes weighted by the probability of occurrence (Tr. JH5, at 61 through 62). He further explained that the expected value would not equal the 50 percent level where the likely margin of potential error is higher on one side of the median than the other (id. at 63 through 64). He noted that the expected value forecast demonstrates that there is a higher probability of error on the deficiency side than on the surplus side (id. at 65 through 66). Mr. La Capra added that, given the magnitude of uncertainty in need, the potential consequences of supply shortages and the long lead times required to develop new resources, a confidence level of 60 to 70 percent is more reasonable than a 50 percent confidence level for supply planning purposes (Exh. EFSB-MN-2).

better able to reflect the potential impacts of the significant uncertainties that affect the timing and magnitude of the need for new energy resources (Exh. EFSB-MN-2).[113,114]

In addition to presenting the above two Massachusetts demand forecasts based respectively on NEPOOL's deterministic forecasting and NEPOOL's probabilistic forecasting, the Company presented the Massachusetts end year CAGR forecast as a useful alternative to the Massachusetts reference forecast (Exh. SCE-22, at 6 through 7). The Company indicated that its end year CAGR forecast methodology assumes that Massachusetts adjusted peak load in 2007 will be the same as forecasted by the Massachusetts reference forecast, but utilizes the average annual 1992-2007 compound growth rate underlying that 2007 peak load level to forecast demand for the intervening years (id.; EFSB-MN-3).[115] The Company stated that, by assuming a constant growth rate consistent with the long-term outcome of the Massachusetts

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113 The Company indicated that its Massachusetts expected value forecast reflects an average annual growth rate in adjusted peak load of 2.50 to 2.83 percent over the 1992-2007 forecast period, depending on which of the Company's three DSM forecasts is used (Exh. SCE-22, at att. RLC-10) (see Section II.A.4.b.i.(B), below).

114 The Company stated that the Massachusetts expected value forecast, combined with the low DSM forecast would be a reasonable high case forecast (Exhs. SCE-22, at 9; EFSB-MN-6). The Company indicated that the Massachusetts expected value forecast, although only the third highest forecast during the early years of the forecast period, incorporates higher peak load growth that allows it to surpass all forecasts by the end of the forecast period (Exh. SCE-22, at att. RLC-10). Specifically, the Massachusetts expected value forecast surpasses the Massachusetts linear regression forecast beginning in 1997 to 1999, depending on which of the Company's three DSM forecasts is assumed, and surpasses the Massachusetts CAGR regression forecast beginning in 2005 under any of the Company's DSM forecasts (id.).

115 To apply the end year CAGR methodology to adjusted peak load, the Company first derived Massachusetts adjusted peak load values for 1992 and 2007 by adjusting NEPOOL's Massachusetts peak load forecast to reflect SCE's DSM assumptions for those years, and then derived a CAGR trend forecast of Massachusetts adjusted peak load for the intervening years (Exh. SCE-22, at att. RLC-10). The Company indicated that its Massachusetts end year CAGR forecast reflects a constant annual growth rate of 2.21 to 2.55 percent, depending on which of SCE's three DSM forecasts is used (id.) (see Section II.A.4.b.i.(B), below).

reference forecast, the end year CAGR methodology dampens the short-term pessimism of the Massachusetts reference forecast (Exh. EFSB-MN-3).[116] The Company added that the use of a constant annual growth forecast for supply planning purposes would decrease the possibility that prolonged periods of oversupply or undersupply of generating capacity would occur (id.).

The Company stated that it developed its two remaining forecasts -- the Massachusetts linear regression forecast and the Massachusetts CAGR regression forecast -- based on performing time series regression analyses of 1974-1991 weather-normalized Massachusetts summer peak load data derived from NEPOOL data (Exh. SCE-22, at 7).[117] The Company stated that historic trends in DSM are reflected in the weather-normalized data that underlies the regression equations, and claimed that a moderate-to-high amount of DSM thus was incorporated in the regression forecasts (Exh. EFSB-MN-4). The Company indicated that the projected growth in Massachusetts peak load would be 179 MW per year under the linear regression forecast[118] and 2.39 percent per year under the CAGR regression forecast (Exh. SCE-22, at att. RLC-6, att. RLC-7). The Company stated that both regression formats show good statistical results for the 1974-1991 historical data (id.).

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116 As an example of the relatively flat, short-term trend, the Company's Massachusetts reference forecast projects 1992-1995 increases in adjusted peak load of 1.42 to 1.99 percent, depending on which of SCE's three DSM forecasts is used (Exh. SCE-22, at att. RLC-10). In terms of annual MW increments, the Company's Massachusetts reference forecast shows average annual increases in adjusted peak load of 128 MW to 181 MW between 1992 and 1995, depending on which DSM forecast is used, and 148 MW to 200 MW between 1992 and 1997 -- the planned on-line date of the proposed project (id.). However, indicative of the higher rate of increase in the longer term, the Company's Massachusetts reference forecast shows average annual incremental increases in adjusted peak load of from 271 MW to 308 MW between 1997 and 2007 (id.).

117 The Company stated that weather-normalized data was not available by state, and that it approximated such data by multiplying NEPOOL's 1974-1991 weather-normalized summer peak load data by the year-to-year ratio of actual Massachusetts summer peak load to actual NEPOOL summer peak load (Exh. SCE-22, at 7).

118 Over the 1992-2007 forecast period, the linear trend corresponds to a CAGR of 1.71 percent (Exh. SCE-22, at att. RLC-10).

The Company asserted that the Massachusetts linear regression forecast represents a reasonable low case, claiming that the Siting Council's West Lynn Decision supports the view that a linear regression forecast constitutes an "approximate minimum" for a long-term forecast (Exh. EFSB-MN-7; SCE Supplemental Brief at 23 through 24).[119] The Company also asserted that the Massachusetts CAGR regression forecast, the highest forecast over all except for the last three years of the forecast period, represents a reasonable high case over the 1992-2004 period (Exhs. SCE-22, at 9 and att. RLC-10; EFSB-MN-6).

(B) DSM Forecasts

The Company stated that it utilized NEPOOL's DSM forecast for Massachusetts, which corresponds to NEPOOL's DSM forecast for New England contained in the reference forecast, to develop a range of DSM forecasts for the Massachusetts need analysis (Exh. SCE-22, at 8). Repeating arguments from its regional need analysis (see Section II.A.3.c.i., above), the Company stated that NEPOOL historically has overforecast DSM, and that, therefore, the Company considers NEPOOL's Massachusetts DSM forecast to be a high case DSM forecast for purposes of the Massachusetts need analysis (id.). Consistent with the regional need analysis, the Company stated that a DSM forecast for Massachusetts which assumes a portion of the planned increase in DSM above 1991 levels, as forecast by NEPOOL, would represent a reasonable base case DSM forecast (id.). The Company stated that it developed a Massachusetts DSM forecast which assumes 75 percent of NEPOOL's planned

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119 Based on the Company's projections of adjusted peak load, the Massachusetts linear regression forecast actually is second highest at the beginning of the forecast period, surpassed only by the Massachusetts CAGR regression forecast (Exh. SCE-22, at att. RLC-10). However, depending on which of the Company's three DSM forecasts is assumed, the Massachusetts linear regression forecast is surpassed by the Massachusetts expected value forecast beginning between 1997 and 1999, by the Massachusetts end point CAGR forecast beginning between 1999 and 2003, and by the Massachusetts reference forecast beginning between 2002 and 2005 (id.). In defending its selection of the linear regression forecast as a reasonable low case, the Company stated that forecasts based on the Massachusetts reference forecast rely on overly pessimistic economic assumptions in the short term (Exh. EFSB-MN-6).

increase in DSM for Massachusetts above 1991 levels as a base case DSM forecast and one which assumes 50 percent of such increase as a low case DSM forecast.[120]

ii. Positions of the Intervenors and Company's Response

The Attorney General argued that the Company's Massachusetts demand forecast methodologies are biased upward and thus overstate likely future load growth (Attorney General Supplemental Brief at 27 through 50). The Attorney General's witness, Dr. Shakow, presented testimony discussing (1) deficiencies in the Company's Massachusetts demand forecasts, and (2) results of an alternative "diagnostic" econometric forecast based on multiple regression analyses (Exh. AG-1S). In addition, the Attorney General criticized the Company's failure to consider individual Massachusetts utility forecasts (Attorney General Supplemental Brief at 25 through 27).

The Attorney General argued that the Company's Massachusetts reference forecast, obtained from NEPOOL, is subject to the same criticisms as the CELT reference forecast used in the Company's regional need analysis (see Section II.A.3.b.ii., above), and noted that NEPOOL itself has disclaimed any intent to present its state-level forecasts for use by individual states in planning state-specific needs (id. at 42 through 44). The Attorney General, therefore, argued that the methodology underlying the 1991 CELT forecast continues to be the most reliable forecasting method of record in this case (id. at 43).

With respect to the expected value forecast, the Attorney General argued that said forecast does not provide a reliable basis for determining regional need due to (1) NEPOOL's methodology in deriving the expected value forecast, and (2) SCE's use of the expected value forecast to develop a base case forecast for the overall 1992-2007 period (id. at 31 through 42).

With regard to NEPOOL methodology, the Attorney General first stated that the forecasted load growth distribution is skewed such that higher loads are more likely to occur

[120] As noted above, the Company's regional need base case DSM forecast assumed 50 percent of the planned increase in DSM levels above 1991 levels, as forecast by NEPOOL. See Section II.A.3.c., above.

than lower loads (Attorney General Supplemental Brief, citing, Exh. SCE-RR-6, at 9). He further argued that NEPOOL's methodology for developing the two components of high-side uncertainty -- the peak-load values associated with the high-load forecast and the probability assigned to that forecast -- was unsound (id. at 33 through 37). Specifically, the Attorney General argued that, in order to develop a high-load forecast, NEPOOL made inappropriate ad hoc adjustments to a rigorously developed economic forecast (id. at 34). The Attorney General explained that NEPOOL, in developing its high-load forecast, rejected an optimistic economic forecast prepared by an independent consultant because it was low relative to recoveries from previous recessions (id., citing, Exh. EFSB N-61(b) at 5 through 7). However, the Attorney General argued that NEPOOL's adjustments conflict with the current state of the economy in that the recent recession was the worst in 20 years and the recovery is modest compared to previous recoveries (id. at 34 through 35, citing, Exh. AG-JH-2; Tr. 14 at 121 through 123, 199).[121] With respect to the second component of high side uncertainty, the assignment of probability to the high-load forecast, the Attorney General argued that NEPOOL derived a probability distribution based on a judgmental process without explanation (id. at 35 through 36).

In addition, the Attorney General argued that the Company compounded NEPOOL errors underlying its probabilistic analysis by utilizing the 1993-1997 expected value forecast to develop a base-case forecast for the years 1992 though 2007 (id. at 38 through 39). In support, the Attorney General argued that a base-case forecast should be (1) identified through a credible forecasting methodology and set of inputs, and (2) subjected to various sensitivities in order to produce a bandwidth around the forecast and that, therefore, the expected value forecast -- itself derived from bandwidths -- is not statistically suited to serve as a base case

121 The Attorney General argued that NEPOOL's rejection of independent data would subject the high-load forecast to the Company's criticism of the short-term forecast -- that ad hoc adjustments to data developed independently would bring into question the forecast's overall objectivity and reliability (Attorney General Supplemental Brief at 34).

forecast (id.).[122] The Attorney General questioned the use of a linear regression of forecast values for 1993 through 1997 to extend the NEPOOL forecast through 2007 (id. at 40 through 42).[123] The Attorney General argued that it was inappropriate to extend the forecast beyond 1997 inasmuch as NEPOOL itself suggested that uncertainty surrounding future load levels and resource availability makes it difficult to perform a meaningful probabilistic analysis over the long-term (id. at 22 through 23, citing, Exh. SCE-RR-6, at 17).

The Attorney General further asserted that the confidence level reflected in the expected value forecast -- 57 percent to 62 percent -- exceeds consistent Siting Board precedent in planning to a 50 percent confidence level (id. at 31 through 32, citing, Exh. SB-JH-RR-8).[124] He argued that the Company did not provide sufficient justification for the Siting Board to depart from such precedent (id.).[125] Finally, the Attorney General argued that SCE offered no evidence to support its use of the ratio of the Massachusetts reference forecast to the regional

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122 The Attorney General further argued that accepting the expected value forecast as a base forecast suggests that a bandwidth should be drawn around the forecast which would be even wider than the expected value forecast (Attorney General Supplemental Brief at 38).

123 Dr. Shakow stated that a "regression analysis properly involves the construction of a fit to actual data" (Exh. AG-204, at 8). He stated that the expected value forecast does not constitute data and that the R^2 values associated with the regression do not demonstrate that the Company has produced a good forecast (id. at 8 through 9).

124 The Attorney General stated that the Company's suggestion that need be determined based on a confidence level greater than 50 percent such that projects would later "hone to the level of demand" would inappropriately defer siting decisions to other review processes (id. at 13 through 14).

125 In addition, the Attorney General argued that the expected value forecast, driven by a high load forecast resulting from the rejection of a rigorous objective forecast and judgmental probability assignment, fails to meet the Siting Board requirement that demand forecasts should be fully described and explicitly and completely documented to allow the Siting Board to "fully understand the forecast from the information presented" (Attorney General Supplemental Brief at 37, citing, 980 C.M.R. §7.03(5)).

CELT reference forecast to derive the Massachusetts expected value forecast from NEPOOL's regional expected value forecast (id. at 39 through 40).[126] The Attorney General stated that the Company's use of such ratio assumes that the peak load uncertainties modeled by NEPOOL and reflected in its regional expected value forecast would affect Massachusetts alone in the same way that they would affect the region as a whole, whereas the Attorney General asserted that these peak load uncertainties are susceptible to state-by-state variation (id. at 39 through 40).

In response to criticism of the expected value forecast, the Company stated that the Siting Board has not definitively established that supply planning should reflect the 50 percent confidence level, but that, instead, the Siting Board has given applicants the opportunity to justify a higher level of planning confidence and has found that planning to a 50 percent confidence level may not satisfy reliability concerns (SCE Supplemental Reply Brief at 14 through 16, citing, EEC Decision, 22 DOMSC at 238-240; Boston Edison Company, 24 DOMSC 125 at 282-286 (1992) ("1992 BECo Decision").

Regarding the Attorney General's argument that NEPOOL has judgmentally selected a high-side demand case which results in an upward bias to the entire expected value forecast, SCE responded that judgmental development of a forecast does not render it invalid (id. at 16 through 18).[127] SCE further argued that the high-side demand forecast is not unreasonably high such that it would bias the entire forecast, but instead is a reasonable high-case scenario because (1) it is based on actual New England economic data, and (2) the most recent economic data has exceeded NEPOOL expectations (id.).[128]

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126 The Attorney General claimed Mr. La Capra admitted that it would be inappropriate to prorate NEPOOL's high demand forecast to Massachusetts based on the reference forecast ratio (Attorney General Supplemental Brief at 40, citing, Tr. JH4, at 94).

127 SCE stated that the development of any load forecast is inherently judgmental (Tr. JH4, at 56 through 57, 82).

128 The Company asserted that the low-case forecast is not a reasonable scenario largely based on unreasonably high electricity price increases and, therefore, it creates a

(continued…)

With respect to the Massachusetts end year CAGR forecast, the Attorney General argued that such forecast inappropriately incorporates an average long-term growth rate to support a time-sensitive need determination and disregards fluctuations in load growth in planning energy supply (id. at 44 through 45). He further argued that, with respect to the years between the first year and the end year, the end year CAGR methodology is not a sophisticated methodology because it abstracts from, rather than incorporates, the NEPOOL 1992 CELT forecast methodology (id. at 46 through 47).[129] Dr. Shakow testified that the end year CAGR methodology denies the reality of the current recession, which he characterized as a recession that is based on structural factors and that is likely to persist over the next several years (Exh. AG-1S at 9). The Attorney General also argued that the Massachusetts end year CAGR forecast is biased upward because the Massachusetts reference forecast, itself, is biased upward (Attorney General Supplemental Brief at n.13). See Section II.A.3.b.ii., above.

The Company responded that capacity planning decisions are fraught with uncertainty, and, therefore, the Attorney General's view that such decisions be made in a time-sensitive manner shows a gross misunderstanding of the complicated and uncertain nature of resource planning (SCE Supplemental Reply Brief at 20 through 21). The Company maintained that basing planning decisions on a well-developed long-term trend is the best way to avoid the extremes of excess capacity and the "far more serious risk" of deficiencies (id. at 21).

With respect to the Massachusetts linear regression forecast and the Massachusetts CAGR regression forecast, the Attorney General argued that such forecasts represent primitive methodologies with demonstrated theoretical and empirical shortcomings, and, therefore, are

[128](…continued)
downward bias to the expected value forecast (SCE Supplemental Reply Brief at 17 through 18).

[129] The Attorney General claimed that the 1992 CELT forecast model projects peak load for a particular year based on the accumulated forecast of peak load levels for preceding years, not on any conception of long-term load growth that is separate from the results of the 1992 CELT forecast model (Attorney General Supplemental Brief at 46).

inadequate to support a determination of Massachusetts need (Attorney General Brief at 47 through 50; Attorney General Supplemental Brief at 47). Dr. Shakow testified that a major drawback of the Company's use of time series regression forecasts is the implicit assumption that continuous growth will occur at an identical rate over the forecast horizon (Exhs. AG-1, at 20 through 21; AG-1S at 9 through 10). The Attorney General argued that, like the end year CAGR methodology, the Company's time series regression forecasts abstract from the business cycle and associated fluctuations in demand, and, thus, are not useful for determining short-term to mid-term need (Attorney General Supplemental Brief at 47 through 49). The Attorney General also argued that simple extrapolation of historical peak load trends fails to incorporate a realistic picture of DSM, because formal DSM programs did not appear until very late in the historical regression period (id. at 48). Finally, taking issue with the Company's assertion that the West Lynn Decision supports the Company's use of the Massachusetts linear regression forecast as a low case, the Attorney General argued that the linear regression forecast in the West Lynn Decision was based on unadjusted load and included a separate forecast of DSM reductions, and thus differed from the Company's application of the linear regression forecast methodology (id. at 49 through 50).

The Company responded that Siting Council precedent supports the use of linear and CAGR regression methodologies to develop alternative forecasts of need (SCE Supplemental Reply Brief at 21 through 22).

In addition to raising concerns with the Company's individual demand forecast methodologies, the Attorney General criticized the Company's approach to selecting a range of demand forecasts for its Massachusetts need analysis (Attorney General Supplemental Brief at 22 through 27). Specifically, the Attorney General argued that: (1) the Company inappropriately presented a multiplicity of demand forecast methodologies as an indication of forecast sensitivity, instead of presenting a chosen "proper forecasting methodology" with reasonable bandwidths to represent forecast sensitivity based on possible future events; (2) the Company made no serious effort to develop a responsible multiple regression forecast based on econometrics; and (3) the Company failed to investigate how its Massachusetts demand forecasts compare to an aggregation of peak load forecasts prepared by Massachusetts utilities for their in-state service areas (id.).

With respect to use of multiple regression, the Attorney General argued that the Company inappropriately rejected that methodology based on five multiple regression analyses conducted by Mr. La Capra (id. at 28 through 31). The Attorney General asserted that Mr. La Capra's choice of regression variables posed multicollinearity problems, i.e., the independent variables were correlated with each other, and that such multicollinearity led to poor statistical results which ensured that the Company's multiple regression analyses would not provide plausible forecasts (id. at 30).

To demonstrate the feasibility of multiple regression forecasts and provide results of such a forecast, Dr. Shakow presented the following two multiple regression analyses of Massachusetts electricity sales by customer class (1) an analysis based on a "relatively elaborate array" of up to six independent variables for each class ("elaborate multiple regression"), and (2) an analysis based on a "more basic model" of up to three independent variables for each class ("basic multiple regression") (Exh. AG-1S at 10 through 13 and exhs. DMS-2, DMS-3). Dr. Shakow stated that, unlike the Company's multiple regression analyses, his elaborate multiple regression analysis showed good statistical results, including correct signs for all independent variables (id. at 11).[130] Dr. Shakow stated that his basic multiple regression forecast indicated that Massachusetts peak load would increase at an average annual rate of 1.47 percent between 1992 and 1998, and 1.33 percent between 1992 and 2007 (id. at 12).

In response, the Company asserted that Dr. Shakow's multiple regression analyses contained several fundamental flaws, including: (1) use of median effective buying income as an independent variable, rather than an average or aggregate measure of personal income;

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130 The Attorney General stated that the elaborate multiple regression analysis was satisfactory for the purpose of indicating the signs of coefficients, but was not suitable for forecasting because the number of degrees of freedom was low (Exh. AG-1S at 47).

(2) use of erroneously high energy loss factors for adjusting historical energy sales data; and (3) use of historical peak load data that was not weather-normalized (SCE Supplemental Brief at 24 through 27). With respect to the choice of an income measure, the Company noted Dr. Shakow's acknowledgement that median effective buying income showed a lower projected rate of average annual growth than aggregate disposable personal income -- 1.1 percent versus 1.8 percent (id. at 26; Tr. JH7, at 36 through 37). The Company argued that, given the admitted flaws, the Siting Board should reject the use of Dr. Shakow's multiple regression analyses for assessing Massachusetts need (SCE Supplemental Brief at 27).

With respect to the comparison with Massachusetts utility forecasts, the Attorney General cited three utility forecasts that show 1992-1997 growth rates of from 0.97 percent to 1.39 percent and longer term growth rates of from 0.99 percent to 1.79 percent, and claimed such growth rates are substantially lower than those reflected in Mr. La Capra's Massachusetts demand forecasts (Attorney General Supplemental Brief at 25 through 27). The Attorney General asserted that a fourth utility projects no need for new capacity until 2002 (id.).

The Company responded that it is preferable to use an integrated state forecast, which is based on common assumptions, rather than rely on a number of individual utility forecasts, which are filed at different times and based on varying assumptions (SCE Supplemental Reply Brief at 13). The Company also argued that Massachusetts utility forecasts are not all available, leaving "missing components … far bigger than the growth rate you're trying to measure," and that, even where available, most such forecasts have not yet been reviewed or approved by the Department (id.).

iii. Analysis

As described above, the Company utilized five demand forecast methodologies for its Massachusetts need analysis, of which one -- the Massachusetts reference forecast -- corresponds to a methodology used in the regional need analysis. The Company and other parties generally adopted positions regarding the Massachusetts reference forecast matching those adopted with respect to the corresponding forecast in the regional need analysis. The Siting Board reviewed those positions in Section II.A.3.b.iii., above.

Consistent with its findings concerning the 1992 reference forecast, the Siting Board finds that the Massachusetts reference forecast is an appropriate base case forecast for use in an analysis of Massachusetts demand for the years 1996 to 2007.

The remaining four Massachusetts demand forecast methodologies -- the expected value forecast, the end year CAGR forecast, the linear regression forecast and the CAGR regression forecast methodologies -- do not represent counterparts to forecast methodologies included in the Company's regional need analysis. Thus, we address below the positions of the parties regarding those Massachusetts demand forecast methodologies.

With respect to the expected value forecast, the Company considers the expected value forecast to be a base-case forecast while the Attorney General expressed methodological concerns with the forecast. In recent proposals to construct generating facilities, the Siting Board reviewed expected value methodologies. Cabot Power Decision, 2 DOMSB at 308-309; Altresco Lynn Decision, 2 DOMSB at 80; EEC (remand) Decision, 1 DOMSB at 441-442. In its reviews the Siting Board noted that the applicants' use of the expected value methodology was akin to the use of a forecast methodology based on planning to a confidence level greater than 50 percent. Id.; 1992 BECo Decision, 24 DOMSC at 279-286. In addressing such methodologies, the Siting Board has found that planning to a confidence level greater than 50 percent may be appropriate for reliability purposes, but indicated that as a basis for approval of such planning, submission of a cost/benefit analysis to support planning to a higher reliability would be required. Id. In addition, the Siting Board noted that a proponent should consider the likelihood that all utilities within NEPOOL would agree to acquire resources based on a confidence level greater than 50 percent. Id.

Here, the Company has not addressed either issue in proposing the Massachusetts expected value forecast as a base case forecast. In order to accept the expected value forecast as a base case forecast, further support would be required including a cost/benefit analysis. Id.

In addition, with respect to the Attorney General's arguments concerning inappropriate extrapolation and underlying judgmental biases, the Siting Board notes that extrapolation of the expected value forecast raises accuracy concerns, particularly if viewed as a base case forecast, however the record does not establish the extent or direction of any actual inaccuracy. While the Attorney General's arguments have possible merit, if the forecast is viewed simply as a possible or high case forecast, the Attorney General's claimed flaws do not warrant rejection of the forecast. Finally, with respect to the Attorney General's criticism of the Company's use of the regional and Massachusetts reference forecasts to develop a ratio for prorating results of the regional expected value forecast to derive the Massachusetts expected value forecast, the record contains no evidence that the Company's prorating approach resulted in a particular bias, upward or downward, in the Massachusetts expected value forecast.[131]

Accordingly, the Siting Board finds that the Massachusetts expected value forecast is an acceptable forecast for use in an analysis of Massachusetts demand, but should not constitute a base case forecast.

With respect to the Massachusetts end-year CAGR forecast, the Company claimed that the long-term CAGR trend dampens the short-term pessimism of the Massachusetts reference forecast, while the Attorney General countered that the end-year CAGR methodology inappropriately abstracts from the 1992 CELT forecast methodology and thereby denies the reality of the current recession. The Attorney General also noted that the concerns he raised regarding long-term upward biases in the underlying 1992 CELT forecast methodology apply to the Company's end-year CAGR forecast as well.

With regard to the Attorney General's concerns about reliance on a long-term trend, the Siting Board agrees that it is important to consider some forecasts that reflect cyclical influences. In addition, the Siting Board recognizes that, by factoring out short-term

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[131] The Siting Board notes that the Attorney General did not suggest an alternative prorating approach that would be more accurate and still provide a practical means for the Company to adapt NEPOOL's expected value analysis to address Massachusetts need.

fluctuations that may be a source of disagreement among different forecasters, the Massachusetts end-year CAGR forecast inevitably loses much of any robustness or sophistication that is present in the underlying forecast. However, the long-term trend underlying a recognized cyclical forecast also is an important consideration, and we do not agree with the Attorney General that forecasts which factor out short-term cycles should be totally excluded from an analysis of future demand growth, particularly where such forecasts are concerned with a longer planning horizon.

In addition, the Siting Board notes that there are some technical considerations that warrant comment regarding the high long-term trend of the Massachusetts end-year CAGR forecast. First, the Company's forecast results show that the Massachusetts end-year CAGR forecast is higher than the Massachusetts reference forecast for the entire 15-year span of the forecast period, excepting the end year itself. While the record does not indicate the reason for the Company's choice of the forecast end year as the basis of its CAGR methodology, we recognize the intuitive logic of using the end year to represent the long-term.

However, we note that the Company defended the CAGR methodology as a means to avoid both underforecasting and overforecasting. As mentioned, the Company applied the CAGR methodology based on the end year 2007, and thereby implicitly incorporated an assumption that the underlying Massachusetts reference forecast had erred only on the side of underforecasting load over the 1992-2007 period. Further, given that the Massachusetts reference forecast shows its most rapid growth over the latter ten years of the forecast period -- with annual increases in Massachusetts peak load ranging from 271 MW to 308 MW per year -- the Company's forecast results are potentially sensitive to its choice of a representative long-term forecast year for purposes of developing the CAGR trend. SCE might have provided a more balanced basis to develop the long-term trend of its forecast if it had used a forecasted load from the Massachusetts reference forecast that was representative of a range of later years in the forecast period, rather than just the end year.

A second technical consideration is the Company's choice of a CAGR format, in particular, to develop the long-term trend of the Massachusetts reference forecast. Recognizing that forecasters often use an end year CAGR value as a means to characterize or label forecasts in general, the Company's choice of the CAGR format has intuitive appeal. However, the Company could have chosen a different format -- the most obvious alternative being a linear format. Here, because the Company used its selected trend format to interpolate annual load growth between two given load levels, the Company's choice of a CAGR format rather than a linear format was conservative with respect to the forecast of peak load for intermediate years of the forecast period, i.e., it tended to understate peak load relative to results that otherwise would have been obtained.

Overall, although the Company may have developed an unrepresentatively high long-term trend by basing its Massachusetts end year CAGR forecast solely on NEPOOL's Massachusetts load forecast for the end year 2007, the Company was conservative in its choice of a CAGR trend rather than a linear trend. Therefore, on balance, the record does not support a conclusion that the Company's end year CAGR methodology produced a trend-based forecast that is biased upward, as argued by the Attorney General.

Accordingly, based on the foregoing, the Siting Board finds that the Massachusetts end year CAGR forecast provides an acceptable forecast for use in an analysis of Massachusetts demand but should not be considered as a base case forecast.

With regard to the Massachusetts linear regression forecast and the Massachusetts CAGR regression forecast, the Company maintains that both time series regression formats provided good statistical results and are consistent with Siting Council precedent, while the Attorney General criticizes the time series forecasts as a primitive approach that abstracts from the business cycle and is not suitable for determining need in the short or intermediate term. In two additional areas of contention, the Company argues that (1) its time series regression forecasts adequately capture a moderate-to-high amount of DSM and (2) its linear regression forecast represents a minimum forecast based on Siting Council precedent, while the Attorney General disputes both points.

As argued by the Company, the Siting Council previously accepted time series regression forecasts for purposes of establishing need. West Lynn Decision, 22 DOMSC at

27-32, 34. We note that, here, only two of the Company's 11 demand forecasts reflect time series regression, given that the Company did not separate out DSM as an adjustment to load for its linear and CAGR regression forecasts.

The Siting Board agrees with the Attorney General's position that time series regression provides no means to capture possible shifts in peak load trends stemming from changes in underlying economic determinants, and thus is an unsophisticated forecast methodology. However, we disagree with the Attorney General's argument that outright rejection of SCE's time series regression forecasts is warranted. Rather, any evidence of theoretical factors detracting from the applicability of a time series regression or other trending forecast affects the weight the Siting Board places on such forecasts in its determination of need.

With regard to DSM, the Siting Board questions the Company's assertion that its time series regression analyses, based on a 1974-1991 historical period, can adequately capture current rates of DSM implementation. As argued by the Attorney General, formal utility-sponsored DSM programs did not appear until late in the historical period used in the Company's regression analyses. Thus, a majority of the peak load data points in the Company's regression analyses cannot reflect the annual amounts of DSM implementation observed in recent years. Therefore, the Company's time series regression forecasts likely do not fully capture DSM trends.

Finally, the Siting Board disagrees with the Company's position that Siting Council precedent supports a conclusion that the Company's linear regression forecast is an "approximate minimum" forecast. First, as argued by the Attorney General, the extrapolated linear regression trend in the West Lynn Decision review was adjusted for DSM in order to derive a demand forecast, as distinct from SCE's linear regression forecast approach which ignored DSM. Second, the Siting Council's holding in the West Lynn Decision was premised on an absence of theoretical factors warranting consideration of lower forecasts. Here, the Attorney General's case concerning possible recent and ongoing structural changes in the New England and national economies, although supported by scant evidence, represents to a limited degree the type of theoretical factor that potentially could warrant consideration of a slower long-term growth trend than reflected in a linear regression analysis of past peak load levels.

Nevertheless, time series regression analyses are a long-recognized benchmark for establishing potential peak load trends, and have been considered in previous Siting Council and Siting Board reviews. Based on the foregoing, the Siting Board finds that the Massachusetts linear regression forecast and the Massachusetts CAGR regression forecast provide acceptable forecasts for use in an analysis of Massachusetts demand, while recognizing that the forecast methodologies are not sophisticated and that possible adjustments may be appropriate to reflect DSM trends over the forecast period. We further note that such forecasts should not be considered for use as base case forecasts.

The Attorney General also criticizes the Company's overall Massachusetts demand analysis for (1) its failure to successfully incorporate a demand forecast methodology based on multiple regression, and (2) its failure to compare forecasts of Massachusetts peak load to an aggregation of peak load forecasts prepared by Massachusetts utilities.

Regarding multiple regression, the Siting Board agrees with the Attorney General that facility applicants should seriously consider such a forecast methodology as an alternative for purposes of regional or Massachusetts need analyses. However, the examples of multiple regression forecasts provided by the Attorney General for diagnostic purposes contained serious flaws -- most notably the use of an inappropriate personal income variable.

We note that the Attorney General did not intend his multiple regression analyses to serve as alternative demand forecasts in this review, instead he characterized them as diagnostic models. Given the flaws in the Attorney General's models, we conclude that they not only are unreliable as a basis for assessing need in this review, but also fall short of establishing that the Company was remiss in its inability to develop a statistically acceptable multiple regression model.

Regarding use of utility forecasts, the Siting Board agrees with the Company that, given inconsistencies in utility forecast timing, methodology and regulatory review, there are legitimate constraints to developing a statewide forecast based on aggregating results from available Massachusetts utility forecasts. However, the Attorney General is correct that utility forecasts provide a valuable check in reviewing results of regional or statewide forecast models, such as those included in the Company's need analysis. Such comparisons do not, in and of themselves, invalidate the results of models provided by the Company that may show significantly greater future demand. However, the evidence of lower utility expectations for future demand inevitably does provide important corroboration for the cautions and qualifications that the Siting Board has raised in its review, above, of some of the Company's higher demand forecasts.

With respect to DSM, the Company developed base, high and low DSM forecasts for Massachusetts by using the 1992 CELT forecast of DSM additions for Massachusetts as its high DSM forecast, and then discounting those additions by 25 percent and 50 percent in order to develop its base DSM forecast and low DSM forecast, respectively. In its review of the Company's regional need analysis, the Siting Board adjusted the Company's DSM forecasts, incorporating a smaller discount factor, based on its review of the Company's analysis of NEPOOL overforecasting of DSM in recent years,[132] to derive the base DSM forecast and basing the high and low DSM forecasts on a different source -- the high and low DSM cases developed by NEPOOL as part of its resource assessment.

NEPOOL's high and low DSM cases are not disaggregated by state. Thus, to adjust the Company's high and low DSM forecasts to be consistent with the regional need analysis, as asjusted by the Siting Board, it is necessary to prorate NEPOOL's high and low DSM cases to Massachusetts based on the ratio of the adjusted base DSM forecasts in the Massachusetts and regional analyses.[133]

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132 Based on review of information provided by the Company for the regional need analysis and Massachusetts need analysis, the Siting Board adjustment of the NEPOOL-forecasted growth in DSM is (1) 11 percent in the regional need analysis, and (2) 8.4 percent in Massachusetts need analysis. See Sections II.A.3.c. and II.A.4.b.i.(B), above.

133 With respect to the demand forecasts incorporating the end year CAGR methodology,
(continued...)

Accordingly, consistent with its findings in the regional need analysis, the Siting Board finds that: (1) an adjustment of the Massachusetts base DSM forecast by 8.4 percent of the increment over 1992 levels is reasonable for purposes of this review; (2) the Company's Massachusetts high DSM forecast should be adjusted to represent Massachusetts' prorated share of the 1992 CELT high DSM case; and (3) the Company's Massachusetts low DSM forecast should be adjusted to represent Massachusetts' prorated share of the 1992 CELT low DSM case.

c. Supply Forecasts

i. Description

The Company stated that it developed base, high and low supply forecasts for Massachusetts which are consistent with the Company's updated regional supply forecasts (see Section II.A.3.d., above) (Exh. SCE-22, at 9 through 12, att. RLC-11, RLC-12, RLC-13, RLC-14). The Company stated that it developed its base Massachusetts supply forecast based on the 1992 CELT forecast of committed capacity that is owned or contracted by Massachusetts utilities, regardless of location, but excluded committed capacity in planned NUG projects not yet under construction (id. at 9 through 10).[134,135]

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[133](...continued) the Siting Board adjustments to DSM require recalculation of the CAGR trend based on new values for DSM and resultant peak load in 2007 (see Section II.A.3.c.iii., above). The new peak load values for 2007 with the adjusted DSM values are 12,402 MW under the base DSM forecast, 12,187 MW under the high DSM forecast and 12,731 MW under the low DSM forecast. The new CAGRs are 2.246 percent under the base DSM forecast, 2.126 percent under the high DSM forecast and 2.425 percent under the low DSM forecast.

[134] The Company stated that it obtained Massachusetts committed capacity information directly from the 1992 CELT Report, except that it made adjustments based on other sources in order to: (1) reflect updated plant retirements and additions; (2) identify Massachusetts' 598 MW share of the Hydro-Quebec contract; and (3) identify Massachusetts' share of the PASNY allocations, amounting to 63 MW from 1995 to 1997 and 71 MW from 1998 to 2007 (Exhs. SCE-22, at 9 through 10, att. RLC-11,

(continued...)

With respect to interstate utilities supplying Massachusetts, the Company stated that the committed capacity of each such utility system was prorated to its Massachusetts service area based on the ratio of Massachusetts to systemwide summer peak load in 1991 (id. at 10).[136] Consistent with its regional need analysis, the Company indicated that it assumed a 22.5 percent reserve margin applicable to overall supply resources of Massachusetts utilities (id. at 14).

To develop the Massachusetts high supply case, the Company stated that it included 50 percent of the total capacity of uncommitted projects included by Massachusetts utilities in the 1992 CELT report, as well as 50 percent of Massachusetts' share of a possible extension of the Hydro-Quebec contract beyond 2000 (id. at 11 through 12). The Company noted that it made no adjustment for the possibility that portions of BECo's 306 MW Edgar project, included in the high case, could be sold to non-Massachusetts utilities (id.).

To develop the low supply case, the Company assumed the unavailability of the Pilgrim unit 1 nuclear facility, and stated such a case was more than an academic possibility based on the Pilgrim facility's history of operating problems (id. at 11). The Company stated that its Massachusetts low supply case thus is consistent with its regional low supply case, which was based on the loss of a representative average nuclear unit rather than a specific nuclear unit or series of units (see Section II.A.3.d., above) (id. at 12-13).

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[134](…continued)
RLC-13, RLC-14; SB-JH-RR-11R).

[135] The Company stated that, if Massachusetts supply were based on nameplate capacity of power plants located in Massachusetts, the base case would reflect approximately 1,200 MW less capacity, resulting in earlier and larger Massachusetts need (Exh. SCE-22, at 9 through 10).

[136] The Company stated that the 1991 ratios for the three interstate utility systems -- NEES, Eastern Utilities Associates ("EUA"), and NU -- are almost identical to the average projected ratios for these systems (Exh. EFSB-MN-9). The Company presented utility forecast information indicating that, between 1991 and 2001, the ratio of Massachusetts to systemwide summer peak load will decrease by 0.023 and 0.004 for NEES and NU, respectively, but will increase by 0.008 for EUA (id., att. MN-9(d)).

In addition to presenting base, high and low Massachusetts supply forecasts, the Company presented a Massachusetts contingency analysis based on a set of contingency scenarios similar to, but more limited than, that utilized in the regional need analysis (see Section II.A.3.d., above) (id. at 12 through 14). The Company indicated that it identified nine Massachusetts contingencies corresponding to nine of the 11 regional contingencies (id.).[137] The Company presented these nine Massachusetts contingency supply forecasts, based on adjusting the Massachusetts base supply forecast to reflect each of the nine Massachusetts contingencies (id.).

ii. Positions of the Intervenors and Company's Response

Consistent with his position regarding the Company's regional supply forecasts, the Attorney General argued that the Company developed Massachusetts supply forecasts and contingencies that understate the future supply likely to be available to Massachusetts utilities (Attorney General Supplemental Brief at 54 through 57, 61 through 65). The Attorney General also argued, again repeating a position he took regarding the regional need analysis, that the Company assumed an unreasonably high reserve margin of 22.5 percent in its base, high and low forecasts and all but two contingency cases (id. at 57 through 60).

The Attorney General also identified 111 MW of uncommitted NUG capacity that is existing or under construction in New England -- specifically, the uncommitted portions of the MASSPOWER, Enron and AES Thames projects -- and argued that, as in the regional need analysis, the Company inappropriately omitted that capacity from its base supply case in the Massachusetts need analysis (id. at 54 through 55). The Attorney General further argued that, given the Company's position that need will arise earlier in Massachusetts than New England as a whole, it is reasonable to assume for purposes of the Company's need analysis that all 111 MW of said NUG capacity will supply Massachusetts utilities (id.).

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137 The two regional contingencies not included in the Massachusetts need analysis are (1) the addition of 40 percent of planned but uncommitted NUGs, and (2) the addition of 80 percent of planned but uncommitted NUGs (Exh. SCE-22, at 12 through 14).

The Company responded that the record provides no basis to determine that the above projects will represent a cost-effective supply for a Massachusetts utility rather than another New England utility (SCE Supplemental Reply Brief at 25). The Company reiterated that its base supply case represents only committed capacity, owned or contracted, and added that the uncommitted NUG capacity is sufficiently captured as a Massachusetts supply contingency (id.).

The Attorney General argued that the Massachusetts high supply forecast, like its counterpart in the regional need analysis, is overly pessimistic in assuming that only 50 percent of planned but uncommitted utility capacity will be available (id. at 66 through 67). He also argued that the Massachusetts low supply forecast should be disregarded because it assumes the unavailability of the Pilgrim unit 1 -- a possibility that is too remote to warrant consideration in a need-for-power analysis (id. at 66).

With respect to the Company's supply contingencies, the Attorney General argued that the Company should have assumed life extensions for 100 percent of planned Massachusetts retirement capacity, rather than 25 percent, given that only one Massachusetts unit is scheduled for retirement (id. at 68 through 69). He also argued that, given the Company's position that Massachusetts need arises earlier than regional need, the Company should have assumed that (1) all of the contingency NUG capacity for New England will be available for Massachusetts, and (2) none of the contingency reduction in Hydro-Quebec capacity for New England will affect Massachusetts (id. at 69, 77 through 78).

With respect to the Company's prorating of future-year interstate utility capacity to Massachusetts, the Attorney General argued that the Company inappropriately utilized ratios of in-state to system-wide peak load as forecast by the individual utilities (Attorney General Supplemental Brief at 56). He argued that, instead, the Company should have used higher ratios to reflect the fact that SCE's forecasted rate of growth in peak load for Massachusetts exceeds that forecasted by the interstate utilities for their respective systems (id.).

iii. Analysis

As described above, the Company developed base, high and low supply forecasts and additional contingency forecasts for its Massachusetts need analysis that are in large part consistent with those used in the regional need analysis. The Company and other parties generally adopted positions regarding the Massachusetts supply forecasts and contingency forecasts matching those adopted with respect to the corresponding forecasts in the regional need analysis. The Siting Board reviewed those positions in Section II.A.3.d., above.

Consistent with its findings regarding assumed reserve margins in the regional need analysis, the Siting Board finds that the Company's reserve margin for the years 1997 through 2000 should be adjusted as follows: (1) 22 percent for 1997; (2) 21.5 percent for 1998; (3) 21 percent for 1999; and (4) 20.5 percent for 2000.

Further, in its review of the regional need analysis, the Siting Board adjusted the Company's high supply forecast to include 66 MW of uncommitted capacity of NUG projects in the region that are existing or under construction. For purposes of the Massachusetts need analysis, it is reasonable to prorate the 66 MW adjustment based on the ratio of the Massachusetts reference forecast to the regional reference forecast. Under that approach, Massachusetts' prorated share of the 66 MW adjustment is 30 MW in each of the years 1997 through 2000. Accordingly, the Siting Board finds that the Massachusetts high supply forecast should be adjusted to include 30 MW of the uncommitted capacity of NUG projects that are existing or under construction.

Among issues that relate only to the Massachusetts need analysis, the Attorney General argues that the outcome of the Company's overall need analysis, specifically the "high" Company forecasts of Massachusetts demand and the earlier occurrence of Massachusetts need relative to regional need, invalidates assumptions the Company made in prorating interstate utility supply and possible future regional capacity changes to develop its Massachusetts supply forecasts. The Attorney General also argues that the Company should not have hypothesized partial realization of potential life extension as a Massachusetts contingency, given the presence of only one candidate facility in Massachusetts. Finally, the Attorney General suggests that the

Company's low supply forecast, hypothesizing the loss of the Pilgrim unit, is a remote possibility.

Regarding invalidation of supply forecast assumptions by forecast results, the Attorney General appears to take the forecast results out of their logical context. First, it is reasonable that a "higher" load in the Massachusetts portion of an interstate utility's service area would be accompanied by a similarly higher load in the non-Massachusetts portion of the utility's service area, reflecting economic influences on a regional or national level. Under that scenario, supply allocation based on the utility's own load forecast still should be reasonably accurate. Second, the Attorney General's position regarding allocation of future capacity changes apparently assumes that the underlying supply options will be offered in years when there is Massachusetts need but not regional need, and that during such years all non-Massachusetts utilities will be uniformly in surplus. While earlier Massachusetts need may suggest that Massachusetts utilities will be more aggressive in obtaining or retaining supplies, there is no basis to conclude that the extreme adjustments suggested by the Attorney General are warranted.

With respect to the Attorney General's concern regarding the supply contingency based on a partial life extension, we note that such discounting is an accepted method of reflecting uncertainty or probability, and is appropriate for a contingency analysis. With respect to the loss of Pilgrim, we note, as in our review of the regional need analysis, that the Company might have discounted its hypothesized loss of that nuclear unit to better reflect the limited probability of such loss. Nonetheless, loss of Pilgrim for an unusually long period was once experienced, and Massachusetts utilities own significant shares of other nuclear units which also potentially could be unavailable for long periods. Thus, the Massachusetts low supply forecast is reasonably consistent with the regional low supply forecast, and the record does not support a rejection or adjustment of the Massachusetts low supply forecast.

Based on the foregoing, and consistent with our findings in the regional need analysis, the Siting Board finds that: (1) the Massachusetts base supply case represents a reasonable base supply forecast for the purposes of this review; (2) the Massachusetts low supply case represents a reasonable low supply forecast for the purposes of this review; and (3) the Massachusetts high supply case, as adjusted by 30 MW of the uncommitted capacity of NUG projects that are existing or under construction, represents a reasonable high supply forecast for the purposes of this review.

Further, consistent with its findings in the regional need analysis, the Siting Board finds that the Company's Massachusetts supply contingency analysis provides an acceptable basis for assessing the potential range of Massachusetts utility capacity positions that might arise over the forecast period.

d. Need Forecasts

i. Description

The Company presented 33 need forecast scenarios based on a comparison of its 11 demand forecasts -- derived from the three methodologies incorporating each of three DSM forecasts and the two methodologies unadjusted for DSM -- with its three supply forecasts, base, high and low (Exhs. SCE-22, atts. RLC-9, RLC-10, RLC-15; SB-JH-RR-11). Comparing all the Company's demand and supply forecasts, the cumulative number and percentage of need forecasts that demonstrate a need for at least 300 MW of capacity would be (1) 32 need forecasts, 97 percent, in 1997 and (2) 33 need forecasts, 100 percent, in 1998 and beyond (id.). The Company indicated that comparison of its base demand forecast -- the Massachusetts expected value forecast with SCE's base DSM assumptions -- and its base supply forecast -- the 1992 CELT capacity forecast with updated information -- showed a need for over 150 MW in the early years of the proposed project, specifically: (1) 955 MW in 1997; (2) 1,301 MW in 1998; (3) 1,659 MW in 1999; and (4) 2004 MW in 2000 (id.). See Table 3.

SCE also presented 99 additional need cases based on (1) adjusting the base supply forecast to reflect each of the Company's nine contingencies which would increase or decrease supply, and (2) comparing those nine adjusted supply forecasts with the 11 demand forecasts ("need contingency cases") (id.). Considering the Company's need contingency cases together with its need forecasts, SCE presented a total of 132 Massachusetts need cases (id.). The results of the overall Massachusetts need analysis indicated that the cumulative number and percentage of need cases that demonstrate a need for at least 150 MW of capacity would be (1) 130 cases, 98.5 percent, in 1997, and (2) 132 cases, 100 percent, in 1998 and beyond (id.).

The Company also presented two sets of additional calculations of Massachusetts need in response to requests of the Siting Board, including alternative need calculations based on assuming a (1) 21 percent reserve requirement instead of a 22.5 percent reserve requirement in the years 1998, 1999, 2000 and 2001 for most of the Company's need cases,[138] and (2) the DSM levels in NEPOOL's high DSM forecast as an alternative to the high DSM levels in the Company's analysis for the three need forecasts that reflect high DSM and base supply (Exhs. SB-JH-RR-11; SB-JH-RR-12). SCE stated that neither the change in assumed reserve margin nor the change in assumed high DSM levels significantly affects the timing of the first year of continuous need for 150 MW or more in the Massachusetts need analysis (id.).[139,140]

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[138] The Company provided recalculations for 110 need scenarios, including all 33 need forecast scenarios and 77 of the need contingency scenarios (Exh. SB-JH-RR-11). The remaining 22 need contingency scenarios involve contingencies that already reflect higher or lower reserve margins, and thus were not included in the requested recalculations (id.).

[139] With the change in assumed reserve margin, the Company's analysis indicated that the first year of continuous need for at least 150 MW would not change for any of the need forecasts (Exh. SB-JH-RR-11; SCE-22, atts. RLC-27, RLC-28, RLC-29). The Company further indicated that, with the 21 percent reserve margin, comparison of its Massachusetts base demand forecast and its Massachusetts base supply forecast showed the following need levels, still over 150 MW, in the early years of the proposed project: (1) 955 MW in 1997; (2) 1,144 MW in 1998; (3) 1,497 MW in 1999; and (4) 1,838 MW in 2000 (Exh. SB-JH-RR-11).

[140] The Company indicated that, with the alternative high DSM levels obtained from NEPOOL's high DSM forecast, its high DSM forecast would be only marginally higher -- for example, 42 MW higher in 1997 (Exh. SB-JH-RR-12). The Company further indicated that, assuming its base supply forecast in conjunction with the alternative high DSM levels, there would be no change in the first year of continuous need for at least 150 MW from the original high DSM scenarios (id.).

ii. Analysis

As noted above, in considering the Company's demand and supply forecasts, the Siting Board has adjusted: (1) the Company's Massachusetts base DSM forecast to reflect discounting of the 1992 CELT DSM levels by 8.4 percent of the increment over 1991 levels; (2) the Company's Massachusetts high DSM forecast to reflect the NEPOOL high DSM case; (3) the Company's Massachusetts low DSM forecast to reflect the NEPOOL low DSM case; (4) the Company's Massachusetts high supply forecast to include the 30 MW of uncommitted capacity of NUG projects that are existing or under construction; and (5) the Company's assumed reserve margin of 22.5 percent to reflect lower levels after 1996, specifically 22 percent for 1997, 21.5 percent for 1998, 21 percent for 1999, and 20.5 percent for 2000.

With respect to the Company's demand forecasts, the Siting Board has accepted the Massachusetts reference forecast as a base case in the long-term, and has accepted the Massachusetts expected value forecast, the Massachusetts end-year CAGR forecast, the Massachusetts linear regression forecast and the Massachusetts CAGR regression forecast as possible forecasts. While accepting the alternative forecasts to the Massachusetts reference forecast as possible forecasts, the Siting Board identified concerns with the alternative approaches. The identified concerns affect the weight the Siting Board places on these forecasts. As a result, for purposes of this review, the Siting Board places more weight on the reference forecast. Accordingly, the Siting Board addresses need based on two compilations of the Company's need forecasts as adjusted (1) a compilation including only those need forecasts incorporating the reference forecast, and (2) an overall compilation including all need forecasts reflecting all three demand forecast methodologies.

Separating out the forecast methodologies as described above, the number of need forecasts that demonstrate a need for at least 150 MW in each year, from 1997 through 2000, is as follows:

Forecast	1997	1998	1999	2000
Massachusetts reference forecast (9 cases)	7 (78%)	9 (100%)	9 (100%)	9 (100%)
Alternative Massachusetts demand forecasts (24 cases)	24 (100%)	24 (100%)	24 (100%)	24 (100%)
Total (33 cases)	31 (94%)	33 (100%)	33 (100%)	33 (100%)

The capacity positions under the Massachusetts need forecasts, as adjusted, are shown in Table 4. Considered with the Massachusetts base DSM forecast, and the Massachusetts base supply forecast: (1) the Massachusetts reference forecast shows a need for 288 MW in 1997; (2) the Massachusetts end-year CAGR forecast shows a need for 612 MW by 1997; (3) the Massachusetts expected value forecast shows a need for 785 MW by 1997; (4) the Massachusetts linear regression forecast shows a need for 921 MW by 1997; and (5) the Massachusetts CAGR regression forecast shows a need for 1,451 MW by 1997.

In sum, 31 of the 33 Massachusetts need forecasts, including the 24 need forecasts that incorporate alternative Massachusetts demand forecast methodologies, show a need for at least 150 MW in 1997 and 33 show a need for at least 150 MW in 1998. In addition, seven of the nine need forecasts that incorporate the Massachusetts reference forecast show a need for at least 150 MW in 1997 and all such forecasts show a need for at least 150 MW in 1998.

Accordingly, based on the foregoing, the Siting Board finds a need for 150 MW or more of additional energy resources in Massachusetts for reliability purposes beginning in 1997. The Siting Board further finds that the Company's need analysis, including its need forecasts and contingency cases, as adjusted, for Massachusetts and New England, demonstrate that Massachusetts' need for 150 MW of additional capacity clearly will occur earlier than New England's need for same.

e. Other Factors

In addition to its analyses of need for capacity, SCE argued that the proposed project would provide significant transmission benefits to the Massachusetts energy supply as a direct result of its location in the southeastern Massachusetts load centers of New Bedford and Fall River (SCE Brief at 97). SCE also argued that the proposed project would produce significant environmental benefits to the Massachusetts energy supply as a result of reduced air emissions due to displacement of more polluting generation (id. at 110 through 112; SCE Supplemental Brief at 119). Consistent with our standard of review, the Siting Board considers the Company's analyses in support of these benefits to determine if they are sufficient to establish need for the proposed project.[141]

[141] The Siting Board notes that the Company presented these analyses prior to the SJC's decision in City of New Bedford in response to our standard of review for need which required that an applicant establish a level of benefits to Massachusetts in addition to regional need. In the EEC (remand) Decision, we revisited our standard of review for need. In that decision, the Siting Board found that need could be established on reliability, economic efficiency, or environmental grounds directly related to the energy supply of the Commonwealth. See Section II.A.1.c., above.

Specifically, the Siting Board noted that benefits which relate directly to the reliability, cost or environmental impact of the energy supply of the Commonwealth include, but are not limited to, economic efficiency benefits to ratepayers, electric transmission benefits, emissions offsets in the region or at the steam host, and gas/oil swaps with local gas distribution companies. The Siting Board also notes that other benefits not related to the energy supply, while not relevant to the review of need for a proposed project, may still be considered in respect to G.L. c. 164 §§ 69I and 69J which requires that proposals to construct energy facilities be consistent with the current health, environmental protection and resource use and development policies as adopted by the Commonwealth.

i. Transmission Benefits

SCE argued that the proposed project would provide both loading and voltage support benefits to Massachusetts by reducing the overall burden on area transmission lines to import power for the local load centers of New Bedford and Fall River during periods of heavy electrical load, and by providing voltage support to the local transmission system through an increased capacity of reactive power[142] (SCE Brief at 97). SCE asserted that relieving such constrained transmission enhances the overall reliability of the regional transmission supply, and that the two centers of heavy local electrical load, New Bedford and Fall River, would realize an improved local supply of power with operation of the proposed facility (Exh. SCE-1, at 4-47). The Company asserted that the former Massachusetts Executive Office of Energy Resources ("EOER"), now the Division of Energy Resources, has acknowledged the local shortages in both supply and reactive power in Southeastern Massachusetts[143,144] (id. at 4-45 through 4-47).

Further, the Company stated that, according to NEPOOL, capacity deficiency problems are critical in Southeastern Massachusetts because the generation sources located there

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142 The Siting Board notes that alternating current transmission lines carry "apparent power" (measured in units of megavolt-amperes ("MVA")) -- which is a complex unit of power that reflects the existence of both "real power" (measured in units of megawatts (MW)) and "reactive power" (measured in units of megavolt-amperes-reactive ("MVARS")). Real power refers to that component of the apparent power which performs useful work, e.g., the turning of a motor's shaft, illumination from a light bulb, heat from a toaster, etc. Reactive power refers to that component of the apparent power which is necessary for the proper operation of some devices -- such as establishing necessary magnetic fields in a motor or transformer -- enabling it to efficiently utilize the real power component to do the useful work.

143 The Company indicated that a 1988 EOER report entitled "Developing Energy Resources: A Five Point Plan," cited new power plants as one of several solutions to address occasional system reliability problems in the greater eastern Massachusetts area (Exh. SCE-1, at 4-46 through 4-47).

144 The Company stated that sources of additional reactive power include both generating units and capacitor banks (Exh. SCE-1, at 4-45 through 4-47).

(Pilgrim, Canal, Brayton Point, and Somerset Stations) are large in size but relatively few in number (id.). The Company added that when any of these generating units is experiencing an outage during peak periods, the import of power to the area is constrained by the capacity limitations of the regional transmission system (id.). SCE indicated that NEPOOL has established sequential operating procedures ("OP4")[145] for addressing capacity deficiencies (id.). The Company stated that NEPOOL's two major reasons for its historic periods of reliance on OP4 procedures are: (1) a shortage of generating capacity in the Southeastern Massachusetts area; and (2) voltage support problems due to a shortage of reactive power in Southeastern Massachusetts which is used to supply the reactive power requirements of such devices as motors, transformers, and air conditioning systems (id.).

Regarding voltage support benefits, the Company stated that the reactive power reserve problem is most critical during the summer months due to the additional reactive loading that results from the operation of air conditioning systems (id.).[146] To address the reactive power shortage, Mr. Roberts testified that the proposed generator at the TEC would be built to specifications with a power factor of 0.85 at full output[147] (Tr. 18, at 81).

The Company acknowledged that the need to implement OP4 operating procedures has been reduced in the affected area since the 1988 EOER report (Exh. SCE-1, at

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145 NEPOOL's established procedure for operating during a capacity deficiency -- OP4 -- utilizes sequential steps including: ordering all generation under NEPOOL control to operate at maximum, claimed capability (Actions 1 and 2); purchasing available emergency power capacity from neighboring power pools while curtailing some NEPOOL interruptible loads (Action 3); implementation of 5-percent voltage reductions (Actions 6 and 7); and requests for voluntary load curtailment by large industrial and commercial customers and initiation of radio and television appeals for voluntary load curtailment (Action 8) (Exh. SCE-1, at 4-45).

146 The Company's witness, Mr. Roberts, indicated that both EUA and TMLP have asked SCE to provide as much reactive power capability as the proposed project would allow (Tr. 18, at 85 through 86).

147 The Company indicated that, based on a power factor of 0.85, the generator at the proposed facility would have an output of 149.6 MW of real power and 92.7 MVARS of reactive power (Tr. 18, at 81).

4-45 through 4-47). The Company added that NEPOOL had cited three primary reasons for the reduced need to implement OP4 operating procedures in Eastern Massachusetts: (1) milder weather; (2) a reinforced transmission interface between the Rhode Island-Eastern Massachusetts-Vermont energy control area ("REMVEC") and a neighboring energy control area which permits an additional 100 MW power flow into the REMVEC area -- including Southeastern Massachusetts;[148] and (3) additional capacitor installations in the REMVEC area since 1988 (id.).

SCE stated that the reconductoring of the existing EUA 115 kV double-circuit transmission lines, required for interconnection of the TEC, would also provide specific reliability benefits (Tr. 18, at 78 through 79). The Company indicated that in addition to the obvious benefit of an improved ability to handle an increased power flow on the regional 115 kV transmission system, the reconductoring would allow EUA to simultaneously add insulators to one of the circuits, thereby decreasing the chances of a lightning-induced outage on one of the lines[149,150] (id. at 17 through 18).

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148 Here, the term interface refers to those segments of major transmission lines which link energy control areas such as the eastern REMVEC area to other areas of transmission supply and distribution.

149 The Company stated that EUA recognizes that its existing double-circuit transmission lines -- into which the proposed facility would connect -- are prone to lightning-induced outages (Tr. 18, at 17). SCE's witness, Mr. Thalmann, explained that the double-circuit transmission lines are supported by steel structures, and added that each line presently contains the same number of insulators, typical of older transmission designs (id. at 17 through 18). Further, Mr. Thalmann stated that during a lightning strike to the steel support structure, both transmission lines are presently prone to a flash over, and both circuits could be tripped at the same time (id.). Mr. Thalmann added that in reconductoring the existing transmission lines, EUA would incorporate a modern transmission design technique by adding insulators to one of the double-circuit lines, enabling one of the lines to flash over with greater ease than the other line, thereby increasing the reliability of the transmission system by an increased probability of maintaining operation of the other line (id.).

150 The Company also stated that in order to minimize electric and magnetic fields

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In Turners Falls Limited Partnership, 18 DOMSC 141, 159 (1988), the Siting Council found that transmission-system-related benefits must be significant and carefully documented in order to demonstrate benefits to Massachusetts as part of an analysis of need.

Here, the record demonstrates that the proposed project potentially could provide load relief to the area transmission system under certain contingencies and thereby delay the need for both transmission system improvements as well as implementation of NEPOOL capacity deficiency operating procedures. However, SCE has not provided any load flow analyses for the Southeastern Massachusetts area to support the Company's position that particular transmission lines used to import power to the area during a period of heavy electrical load would, with or without a contingency, approach their power rating limits without operation of the proposed project. Further, the Company did not identify either the timing or the cost of an actual improvement to address an identified need based on (1) expected load growth and applicable reliability standards, or (2) specific confirmation of a utility plan to implement such improvements.

With respect to voltage benefits, we note that SCE identified a TEC contribution of up to 92.7 MVARS for reactive power support. However, the degree to which such reactive power support would be useful in helping to stabilize voltage levels due to any reactive power deficiencies was not substantiated. Further, SCE failed to document the cost and timing of measures that the affected utilities would consider and select to address any such deficiencies in reactive supply, with or without the proposed project.

With respect to reconductoring benefits, we note that the addition of insulators by EUA to one of the two 115 kV regional transmission lines on the double-circuit structure, into which the proposed facility would connect, is likely to increase transmission reliability in the event of an electrical storm. However, SCE failed to document either the frequency of lightning-

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[150](…continued)
("EMF") on EUA's existing transmission lines, EUA agreed to implement line positioning techniques at the time any reconductoring is done to accommodate the proposed facility (Exh. EFSC-RR-134). (See Section III.C.2.a.x., below).

induced outages on either of the subject transmission lines, or the cost and timing of measures utilities would consider to address such reliability concerns in the absence of the proposed project and associated reconductoring effort.[151]

Thus, SCE has identified only the potential for the proposed project to provide local reliability benefits by: (1) deferring the likely need for transmission projects to meet increased local load; (2) possibly deferring the likely need for new capacitors on the affected lines to restore some magnitude of reactive power; and (3) improving the lightning-induced outage frequency on a single, existing regional 115 kV transmission line with operation of the proposed project. While such contributions to meeting transmission related reliability concerns clearly represent potential benefits to Massachusetts, the Siting Board must evaluate the timing of identified needs and the availability and cost of alternatives, in order to determine whether such benefits are of sufficient magnitude to contribute to a showing of need for the proposed project. Here, the Company has not provided the information necessary to enable us to do so.

Accordingly, the Siting Board finds that the Company has not established a need for the proposed project based on transmission benefits.

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151 Regarding EUA's agreement with SCE to utilize line placement techniques in order to minimize EMF levels on its existing transmission lines during the proposed reconductoring, the Siting Board recognizes that the possible reduction of EMF levels, with operation of the proposed project, along the regional 115 kV transmission line ROW could benefit populations situated in proximity thereto. We note, however, that the Company did not provide a comparison of EMF levels along the EUA ROW -- with and without operation of the proposed project -- that would allow us to determine the likelihood and magnitude of any EMF reduction. Further, such efforts constitute mitigation of environmental impacts associated with the operation of the proposed facility rather than significant reliability, cost or environmental benefits associated with the energy supply which could prove sufficient to contribute to a showing of need for a new generating facility.

ii. Dispatch

(A) Description

SCE asserted that installation and operation of the proposed project would change the regional dispatch of electric generating units by NEPOOL, which would result in lower regional emissions of several criteria pollutants than without the proposed project, thereby ensuring that the proposed project would have a minimum impact on the environment with respect to air quality (SCE Brief at 110 through 112; SCE Supplemental Brief at 119). In support, the Company provided an analysis indicating that, over the five-year period from 1995 to 1999, operation of the proposed project would result in an average annual net decrease in regional emissions of 1916.7 tons of sulfur dioxide ("SO_2"), 1440.0 tons of nitrogen oxides ("NOx"), 131.5 tons of particulate matter ("PM-10") and 10.5 tons of volatile organic compounds ("VOC"), but an average annual net increase of 642.5 tons of carbon monoxide ("CO") (Exh. SCE-9, exh. 15).[152]

To develop its estimates of emissions changes, the Company determined the annual unit-by-unit generation for the region consistent with NEPOOL dispatch procedures, both with and without the proposed project's generation of 1,116.9 gigawatt hours ("gwh") (id.; Exh. EFSB-RR-161). The Company's analysis reflected NEPOOL's 1990 CELT Report forecast of annual energy requirements over the period -- an increase of 9,956.2 gwh, from 125,669.5 gwh in 1995 to 135,625.7 gwh in 1999 (Exhs. SCE-1, at 4-34; EFSB-RR-161).[153] With respect to supply, the analysis reflected NEPOOL's 1991 CELT Report forecast of annual committed capacity, and assumed that member utilities also would acquire new gas-fired combustion turbine capacity in sufficient amounts to meet the region's annual peak load capacity

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152 The Company also prepared an analysis of the impacts of dispatch of a gas/oil combined-cycle alternative which provided that operation of a gas/oil combined-cycle alternative would result in an average annual net decrease in regional emissions of 2,867.5 tons of SO_2, 2,048.7 tons of NOx, 166.6 tons of PM-10, 280 tons of CO, and 35.7 tons of VOC (Exhs. SCE-9, exh. 15 (rev.); EFSB-RR-161).

153 The Siting Board notes that the Company did not use NEPOOL's energy forecast from the then-current 1991 CELT Report (Exhs. SCE-1, at 4-34; EFSB-RR-161). In the EEC Decision, the Siting Council found that the 1991 CELT Report demand forecast should not be used for evaluating regional need. 22 DOMSC at 235-236.

requirements (Exhs. SCE-9, at 9, 19).[154] The Company estimated emission rates for existing units based on fuel sulfur content, assumed regulatory emission caps, and facility-specific heat rates (Exh. SCE-1, at 4-37).

In claiming environmental benefits from displacement of existing generation, SCE stated that its analysis reflected only one actual unit retirement during the 1995-1999 period -- a planned retirement of a 28 MW unit in November, 1995 (Exhs. EFSB-RR-161; EFSB 90-100R Tr. 28, at 28 through 29). With respect to dispatch effects on other units, the Company stated that its analysis reflected reductions in annual generation for a number of the region's higher cost units once the proposed project is on-line (Exh. EFSB-RR-161; EFSB 90-100R Tr. 28, at 26 through 27). However, the Company acknowledged that the analysis also shows a year-by-year increase in the annual generation by the same higher cost units over the 1995-1999 period as a result of continuing load growth (Exhs. EFSB-RR-161; EFSB-5; EFSB 90-100R Tr. 28, at 17 through 32).

In terms of fuel mix, the Company's analysis indicated that the generation displaced by operation of the proposed project would consist almost entirely of existing and planned supply resources using oil or natural gas as a primary fuel (Exh. EFSB-RR-161).[155] At the same time, the Company's analysis indicated that oil-fired generation will account for a majority of the 1995-1999 increase in annual generation projected by NEPOOL for the region, with or without availability of the proposed project (Exhs. EFSB-5; EFSB-RR-161; EFSB 90-100R Tr. 28, at

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154 The Company indicated that the basic assumptions, including fuel price forecasts, unit availability factors, fuel mix for dual-fuel units (305 days oil, 60 days gas), dispatch of committed, existing NUG units, and existing unit costs were consistent with the basic assumptions reflected in the economic efficiency analysis (see Section II.A.3.f., above) (Exh. SCE-9, at 19).

155 The Company's analysis showed projected savings in annual oil-fired generation of 673.1 gwh in 1995 increasing to 789.1 gwh in 1999 -- savings which account for 60.3 to 70.7 percent of the displacement provided by the proposed project's total annual generation of 1,116.9 gwh (Exh. EFSB-RR-161; EFSB 90-100R Tr. 28, at 31).

17 through 22).[156] While defending the appropriateness of its analysis for demonstrating the emissions backout potential of the proposed project over the 1995-1999 period, the Company noted that it would be necessary to incorporate additional supply options not included in its analysis in order to permanently avoid or minimize emissions increases from the region's existing supply resources (EFSB 90-100R Tr. 28, at 26 through 30).[157]

In addition, the Company stated that of the 1,116.9 gwh of existing regional generation that would be displaced by the proposed project, an annual average of 462.8 gwh would represent generation by facilities located in Massachusetts (Exh. SCE-9, exh. 15, exh. 16). The Company indicated that, over the five-year period from 1995 to 1999, operation of the proposed project would result in an average annual net decrease in Massachusetts emissions of 631.4 tons of SO_2, 640.7 tons of NOx, 44.6 tons of PM-10 and 3.2 tons of VOC, but an average annual net increase of 253.5 tons of CO (Exh. EFSB-RR-160).

(B) Position of the Attorney General

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156 Specifically, the Company's analysis reflected increases in oil-fired generation between 1995 and 1999 of 6,910.8 gwh with availability of the proposed project throughout the period, and 7,027.9 gwh without availability of the proposed project, representing 69.4 percent and 70.6 percent, respectively, of the overall 9,956.5 gwh increase in annual generation projected by NEPOOL for that period (id.).

157 Mr. La Capra explained that the initial displacement of existing generation and its associated emissions could be made permanent by optimizing the regional supply mix over time -- in particular by continuing to add new lower cost units that would be dispatched ahead of such existing generation (EFSB 90-100R Tr. 28, at 26 through 30). However, the Company noted that, under a logical long-term supply plan, some of the existing intermediate and lesser duration units that initially would be displaced by the proposed project eventually might be replaced by combustion turbine or other peaking units rather than by base load units such as the proposed project (id. at 33 through 36).

The Attorney General argued that the Company has not demonstrated that the Massachusetts' environment would benefit from the displacement of existing generation associated with operation of the proposed facility (Attorney General Brief at 114 through 117). The Attorney General argued that the Company's emissions displacement analysis unreasonably assumed that future power plants would be limited to gas turbines rather than a mix of resource options (id. at 114 through 116). In addition, the Attorney General stated that the emissions displacement analysis fails to take into account the effect of new environmental regulations such as the Clean Air Act Amendments of 1990, on the emission rates of existing and new facilities thereby overstating the effects of the proposed project (id. at 116 through 117). The Attorney General further argued that the Company's analysis indicates that the gas/oil combined cycle alternative would displace significantly greater emissions than the proposed project.

(C) Analysis

The Siting Board has held that a project proponent must provide full documentation of its assumptions pertaining to environmental benefits associated with the dispatch of generation capacity. Cabot Power Decision, 2 DOMSB, at 326-327; 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 Council 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 three 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.[158] Cabot Power

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158 In the Cabot Power Decision, 2 DOMSB at 324-325 and Altresco Lynn Decision, 2 DOMSB at 97-102, the Siting Board reviewed the most complete dispatch analyses to date -- 19 to 20-year dispatch analyses which assumed that energy requirements would be met by currently claimed committed capacity and, as necessary, a range of
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Decision, 2 DOMSB at 327-329; Altresco Lynn Decision, 2 DOMSB at 100-102; EEC (remand) Decision, 1 DOMSB at 325-335. However, the Siting Board identified shortcomings of those applicants' dispatch analyses for addressing the potential for long-term air quality benefits including: (1) the assumption that displaced generation would be increasingly redispatched 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 Power Decision, 2 DOMSB at 328; Altresco Lynn Decision, 2 DOMSB at 100; EEC (remand) Decision, 1 DOMSB at 332-333.

The Siting Board recognized in those reviews that load growth represents a given for purposes of the Company's dispatch analysis, and that the analysis must assume dispatch of available capacity to meet load growth over time. Cabot Power Decision, 2 DOMSB at 327-328; Altresco Lynn Decision, 2 DOMSB at 100; Eastern (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 permanently retired, there would be significant potential for that project to provide long-term benefits through displacement of such generation.[159] 1 DOMSB at 333.

Here, SCE has provided the Siting Board with a five-year analysis of dispatch effects on state and regional emissions for the period 1995-1999 which is similar to the analysis reviewed by the Siting Board in the EEC (remand) Decision, 1 DOMSB at 325-329. The SCE analysis includes sufficient documentation regarding the methodology and assumptions used in the calculations of the net impact that the proposed project would have on total emissions --

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[158](…continued)
generation expansion scenarios.

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

from generation facilities located in both Massachusetts and the New England region -- for the Siting Board to be able to evaluate whether there would be significant dispatch related benefits to the regional and Massachusetts energy supply specific to operation of the proposed project.

For the purposes of assessing environmentally based need in Massachusetts, the Siting Board here focuses primarily on SCE's calculations of the net impact that the proposed project would have on the total emissions from generating facilities located in Massachusetts. SCE's analysis indicates that the operation of the proposed project would clearly reduce the net emissions in Massachusetts of four of the five pollutants analyzed: SO_2, NOx, PM-10, and VOCs. These net reductions, however, are offset to a degree by the higher net Massachusetts emissions of CO. However, the Siting Board notes that emissions of two pollutants which are of greatest concern to regional acid rain and ground-level ozone problems, i.e., SO_2 and NOx, would be reduced significantly by the operation of the proposed project.

Thus, viewed in the context of a few initial years of operation, the Company's analysis provides a reasonably realistic basis to conclude that Massachusetts would receive a level of air quality benefits reasonably attributable to the proposed project.

Viewed over the life of the project, however, the Company's analysis falls short of providing a realistic basis to attribute long-term environmental benefits to the proposed project. The company's analysis is similar to those in previous reviews in that it: (1) allows the displaced generation to be increasingly redispatched over time with continued load growth; (2) assumes that the emissions rates from respective units in the analysis, in lb/MMBtu, remain constant over time; and (3) includes no explicit assumptions or scenarios demonstrating a potential for holding Massachusetts emissions to current or lower levels through planned or accelerated retirement of existing generation.

In addition, unlike the analyses reviewed in the Enron Decision, 23 DOMSC at 69-73, the Altresco-Lynn Decision, 2 DOMSB at 97-102, and the Cabot Power Decision, 2 DOMSB at 324-329, the Company's analysis fails to span a reasonable long-term time frame, such as 20 or 30 years, and fails to reflect possible capacity expansion plans in the region incorporating technologies other than gas-fired combustion turbine units.[160] As acknowledged by the Company, it would be necessary to continue to add new low cost units, which would be dispatched ahead of existing generation, in order to optimize the regional supply mix in a manner likely to permanently avoid or minimize emissions increases. Clearly, a regional generation expansion plan that includes a substantial mix of base load units, not just combustion turbine units as assumed in the Company's analysis, is likely to meet cost and reliability objectives as well.

The Siting Board, therefore, finds that SCE has demonstrated that the proposed project could provide short-term environmental benefits to Massachusetts based on reduction of air pollutant emissions from generating units in Massachusetts provided it comes on-line prior to 2000. However, the Siting Board finds that SCE has not demonstrated that the proposed project would provide long-term environmental benefits to Massachusetts based on reduction of air pollutant emissions from generating units in Massachusetts.

Accordingly, the Siting Board finds that SCE has failed to establish that the proposed project is needed on environmental grounds.[161]

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160 In addition, unlike the analyses reviewed in the Enron Decision, the Altresco-Lynn Decision and the Cabot Power Decision, the Company's analysis fails to address the impact of operation of the proposed facility on emissions of CO_2 and methane.

161 The Siting Board takes administrative notice of the recently promulgated Department of Environmental Protection regulation 310 C.M.R. 7.00 Appendix B on Emission Banking, Trading, and Averaging. The purpose of this regulation is to establish a program of emission banking and trading for NOx, VOC and CO whereby persons and companies who reduce emissions below levels required by state and federal regulations can "bank" the surplus reduction for use at a later date or transfer the reduction to another party.

In order to help ensure that the findings in this decision regarding net emissions reduction benefits of NOx and VOC for the Massachusetts emissions inventory are realized if the proposed facility is constructed, the Siting Board strongly encourages SCE to make use of the emerging emission reduction trading market. In this regard, the Siting Board recommends that prior to construction of the proposed TEC facility, the Company reassess the plant's net emissions effects in Massachusetts for NOx and

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5. Findings and Conclusions on Need

In Sections II.A.2, 3 and 4, above, the Siting Board has made the following subsidiary findings:

- that SCE has not established that its proposed project is needed for economic efficiency or reliability reasons in Massachusetts through signed and approved PPA's.
- that the reference forecast is an appropriate base case forecast for use in the analysis of regional demand for the years 1996 through 2007;
- that the GNP forecast provides an acceptable forecast for use in an analysis of regional demand, while recognizing that the forecast methodology is not sophisticated and that possible adjustments may be needed to reflect DSM trends over forecast period;
- that the linear regression forecast and CAGR regression forecast provide acceptable forecasts for use in an analysis of regional demand, while recognizing that the forecast methodologies are not sophisticated and that possible adjustments may be needed to reflect DSM trends over forecast period;
- that it is appropriate to adjust the 1992 CELT DSM levels in the base case;
- that it is appropriate to adjust the 1992 CELT DSM levels by 11.4 percent of the increment over 1991 levels and that such adjusted level represents a reasonable base DSM case for the purposes of this review;
- that the Company's low DSM forecast should be adjusted to represent the 1992 CELT low DSM forecast;
- that the Company's high DSM forecast should be adjusted to represent the 1992 CELT high DSM forecast;

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[161](…continued)
VOCs and obtain emission reduction credits as may be necessary to ensure a net emissions benefit for each pollutant that will assist the Commonwealth in meeting the requirements of the Clean Air Act Amendments of 1990. This recommendation is subject to the availability of an approved emissions trading regulation under 310 C.M.R. 7.00 Appendix B or any potential successor to this regulation.

- that the base supply case, including 83 MW of the committed capacity of NUG projects that are existing or under construction, represents a reasonable base supply forecast for the purposes of this review;
- that the low supply case, including 83 MW of the committed capacity of NUG projects that are existing or under construction, represents a reasonable low supply forecast for the purposes of this review;
- that the high supply case, including 83 MW of the committed capacity of NUG projects that are existing or under construction, and as adjusted by 66 MW of the uncommitted capacity of NUG projects that are existing or under construction, represents a reasonable high supply forecast for the purposes of this review;
- that the Company's regional supply contingency analysis provides an acceptable basis for assessing the potential range of regional capacity positions that might arise over the forecast period;
- that the Company's reserve margin for supply forecasts including the Seabrook unit in the years 1997 through 2000 should be adjusted as follows: (1) 22 percent for 1997; (2) 21.5 percent for 1998; (3) 21 percent for 1999; and (4) 20.5 percent for 2000;
- that it is appropriate to explicitly consider need for the proposed facility within the 1997 to 2000 time period;
- that there will be a need for 150 MW or more of additional energy resources in New England for reliability purposes beginning in 2000 and beyond;
- that the Company has not established that New England will need 150 MW or additional energy resources from the proposed project for economic efficiency grounds;
- that the Massachusetts reference forecast is an appropriate base case forecast for use in an analysis of Massachusetts demand for the years 1996 to 2007;
- that the Massachusetts expected value forecast is an acceptable forecast for use in an analysis of Massachusetts demand, but should not constitute a base case forecast;

- that the Massachusetts end year CAGR forecast provides an acceptable forecast for use in an analysis of Massachusetts demand but should not be considered as a base case forecast;
- that the Massachusetts linear regression forecast and the Massachusetts CAGR regression forecast provide acceptable forecasts for use in an analysis of Massachusetts demand, while recognizing that the forecast methodologies are not sophisticated and that possible adjustments may be needed to reflect DSM trends over the forecast period;
- that: (1) an adjustment of the Massachusetts base DSM forecast by 8.4 percent of the increment over 1992 levels is reasonable for purposes of this review; (2) the Company's Massachusetts high DSM forecast should be adjusted to represent Massachusetts' prorated share of the 1992 CELT high DSM case, and (3) the Company's Massachusetts low DSM forecast should be adjusted to represent Massachusetts' prorated share of the 1992 CELT low DSM case;
- that the Company's reserve margin for the years 1997 through 2000 should be adjusted as follows: (1) 22 percent for 1997; (2) 21.5 percent for 1998; (3) 21 percent for 1999; and (4) 20.5 percent for 2000;
- that the Massachusetts high supply forecast should be adjusted to include 30 MW of the uncommitted capacity of NUG projects that are existing or under construction;
- that: (1) the Massachusetts base supply case represents a reasonable base supply forecast for the purposes of this review, (2) the Massachusetts low supply case represents a reasonable low supply forecast for the purposes of this review, and (3) the Massachusetts high supply case, as adjusted by 30 MW of the uncommitted capacity of NUG projects that are existing or under construction, represents a reasonable high supply forecast for the purposes of this review;
- that the Company's Massachusetts supply contingency analysis provides an acceptable basis for assessing the potential range of Massachusetts utility capacity positions that might arise over the forecast period;

- that need for 150 MW or more of additional energy resources in Massachusetts for reliability purposes will begin in 1997;
- that the Company's need analysis, including its need forecasts and contingency cases, as adjusted, for Massachusetts and New England, demonstrate that Massachusetts' need for 150 MW of additional capacity clearly will occur earlier than New England's need for same;
- the Company has not established a need for the proposed project based on transmission benefits;
- SCE has demonstrated that the proposed project could provide short-term environmental benefits to Massachusetts based on reduction of air pollutant emissions from generating units in Massachusetts provided it comes on-line prior to 2000; and
- SCE has not demonstrated that the proposed project would provide long-term environmental benefits to Massachusetts based on reduction of air pollutant emissions from generating units in Massachusetts.

Based on the foregoing, the Siting Board finds that the Company's need analyses demonstrate that Massachusetts' need for 150 MW of additional capacity clearly will occur earlier than New England's need for same. Given the demonstration of earlier need in Massachusetts than New England, it is clear that, for all years in which there will be a regional need for the proposed project, i.e., for the years 2000 and beyond, the proposed project would provide a necessary energy supply for the Commonwealth.[162] The proposed project on-line

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[162] The Siting Board hereby takes administrative notice of recent electric forecast cases concluded by the Department and the Siting Council. In Fitchburg Gas and Electric, 24 DOMSC 322, Table 3 and Table 4 (1992), the Siting Council approved a forecast showing that in the summer of 1995, the last year of its forecast, Fitchburg Gas and Electric Company would have a total capacity of 102.10 MW, resulting in a surplus of 19.1 MW over its "capability responsibility" of 83.0 MW and a surplus of 26.2 MW over its summer peak load of 75.9 MW (at Table 3 and Table 4). In Boston Edison Company, 24 DOMSC at 303 (1992), the Siting Council found that Boston Edison Company would have surplus capacity of 149 MW in 1996 and 120 MW in 1997, the last year included in its forecast. In Eastern Utilities Associates, DPU 92-214, (1993), (continued...)

date, however, is 1997. Thus, the Siting Board evaluates whether the project is needed beginning in the year 1997.

In the EEC (remand) Decision, 1 DOMSB at 419, the Siting Board noted that an applicant could establish that a regional capacity surplus might not be available to meet a Massachusetts capacity deficiency as a result of transmission or other reliability constraints. The Siting Board further noted that an applicant could establish that reliance on a regional capacity surplus would be contrary to providing a necessary energy supply at the lowest possible cost with the least environmental impact.

However, this recognition was set out in the EEC (remand) Decision after the record in this proceeding was fully developed. Thus, in this case, a record on this issue has not been developed. The record shows that for the years 2000 and beyond there is a need of 150 MW or more for both Massachusetts and the region. However, the record is unclear regarding the ability of Massachusetts utilities to acquire surplus supplies from out-of-state providers in years in which there is a Massachusetts deficiency of 150 MW or more, and either a regional deficiency of less than 150 MW, or a regional surplus. Therefore, based on the

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[162](…continued)
the Department approved a forecast showing that for 1996, the last year in its forecast, Eastern Utilities Associates would have a base case summer peak load surplus of 197.6 MW. In Commonwealth Electric Company\Cambridge Electric Light Company, DPU 91-234, Table 3 (1993), the Department approved a forecast indicating that the Cambridge Electric Light and Commonwealth Electric Companies would have a supply surplus through the year 2000, specifically a surplus of 116 MW in the winter of that year. The Department and the Siting Council approved settlements in four other proceedings filed pursuant to 220 C.M.R. § 10.00 et seq., the Integrated Resource Management Regulations. However, these settlements do not establish precedent nor does the Department's acceptance of the settlements constitute a determination or finding on the merits of any aspect of these proceedings. See, Fitchburg Gas & Electric Co., D.P.U. 92-181, at 22 (1993); Boston Edison Company, D.P.U. 92-265 (1993); Western Massachusetts Electric Company\Northeast Utilities, D.P.U. 92-88, at 9-10 (1992); Massachusetts Electric Company\New England Power Company, EFSC 91-24\D.P.U. 91-114, at 5 (1991).

record, the Siting Board is unable to determine that the proposed project is needed to provide a necessary energy supply for the Commonwealth prior to the year 2000.

The Siting Board notes that a similar disparity occurred between the timing of Massachusetts and regional need in three previous reviews of proposed generating facilities. In the EEC (remand) Decision, 1 DOMSB at 497-498, a review of a proposed 300 MW coal-fired facility, the Siting Board found that based on the record in that proceeding there was a need for at least 300 MW of additional energy resources in New England for reliability purposes beginning in 2000 and a need for at least 300 MW of additional energy resources in Massachusetts for reliability purposes beginning in 1998. In that decision, the Siting Board determined that it was appropriate to require the Company to submit signed and approved PPAs as evidence of the need for the proposed project to provide a necessary energy supply for the Commonwealth. The Siting Board found that the amount of facility output subject to signed and approved PPAs that would be sufficient to establish Massachusetts need would depend on other factors which contribute to Massachusetts need as well as the size and type of facility. Thus, the Siting Board found that the submission of (1) signed and approved PPAs which include capacity payments for at least 75 percent of the proposed project's electric output, and (2) signed PPAs which include capacity payments with Massachusetts customers for at least 25 percent of the proposed project's electric output which is the result of a competitive resource solicitation process beginning in 1993 or beyond and which is approved pursuant to G.L. c. 164, sec. 94A would be sufficient evidence to establish that the proposed project will provide a necessary energy supply for the Commonwealth. See, EEC (remand) Decision, 1 DOMSB at 499.

In the Cabot Power Decision, 2 DOMSB at 300, 319, a review of a proposed 235 MW natural gas-fired facility, the Siting Board found that based on the record in that proceeding there was a need for at least 235 MW of additional energy resources in New England for reliability purposes beginning in 2000 and a need for at least 235 MW of additional energy resources in Massachusetts for reliability purposes beginning in 1998. In addition, the Siting board found economic efficiency need in 2000 or later. In that decision, the Siting

Board also determined that it was appropriate to require the Company to submit PPAs as evidence of the need for the proposed project to provide a necessary energy supply for the Commonwealth. However, the Siting Board noted that, while in both the EEC (remand) Decision and the Cabot Power Decision the proposed project was found to be preferable to alternatives in terms of providing a necessary energy supply for the Commonwealth with minimum environmental impact at least cost, in the EEC (remand) Decision, the Siting Board found that the gas-fired alternative offered significant environmental benefits relative to the proposed project, whereas in the Cabot Power Decision, the proposed project was preferable to all alternatives with respect to both environmental impacts and cost. Thus, the Siting Board found that submission of signed and approved PPAs which include capacity payments for at least 75 percent of the proposed project's output would be sufficient to establish that the proposed project would provide a necessary energy supply for the Commonwealth. Id. at 333. See also, Altresco Lynn Decision, 2 DOMSB at 61, 92, 106.

Here, SCE proposes to construct a 150 MW, coal-fired facility. As noted above, the amount of facility output subject to signed and approved PPAs sufficient to establish Massachusetts need would be dependent on the size and type of facility as well as other factors which contribute to need. The proposed project has established need on reliability grounds begining in 2000. Further in comparing the proposed project to technology alternatives, the proposed project was found to be preferable to alternatives in terms of providing a necessary energy supply for the Commonwealth with minimum environmental impact at least cost (see Section II.B., below). However, similiar to the EEC (remand) Decision, the gas-fired alternative would offer significant environmental benefits relative to the proposed project (see Section II.B., below).

Therefore, in light of the need for the proposed project beginning in the year 2000 on reliability grounds, the Siting Board finds that submission of (1) signed and approved PPAs which include capacity payments for at least 75 percent of the proposed project's electric output, and (2) signed PPAs which include capacity payments with Massachusetts customers for at least 25 percent of the proposed project's electric output which is the result of a competitive resource solicitation process beginning in 1993 or beyond and which is approved pursuant to G.L. c. 164, § 94A, will be sufficient evidence to establish that the proposed project will provide a necessary energy supply for the Commonwealth. SCE must satisfy this condition within four years from the date of this conditional approval. SCE will not receive final approval of its project until it complies with this condition. The Siting Board finds that, at such time that SCE complies with this condition, SCE will have demonstrated that the proposed project will provide a necessary energy supply for the Commonwealth.

B. Alternative Technologies Comparison

1. Standard of Review

a. Positions of the Parties

i. The Company's Position

SCE asserted that G.L. c. 164, § 69J establishes detailed filing requirements for petitions to construct energy facilities and enumerates the factors the Siting Board must consider in order to approve a petition to construct such a facility (SCE Supplemental Brief at 58 through 59). The Company explained that the overall policy direction from the Legislature to the Siting Board "to provide a necessary energy supply for the [C]ommonwealth with a minimum impact on the environment at the lowest possible cost," requires the Siting Board to balance three criteria (id. at 58). These three criteria are: (1) the necessity of reliable energy supplies; (2) the cost of the proposed project; and (3) the environmental impact of the proposed project (id.).

SCE cited the SJC's decision in City of New Bedford as support for the premise that the Siting Board is required to balance these three statutory objectives (id., at 59, citing, City of New Bedford, 413 Mass. at 485). SCE maintained that the Siting Board, therefore, is to apply its expertise in balancing these conflicting objectives when considering new facilities (SCE Supplemental Brief at 59). Further SCE argued that a necessary implication of the SJC's decision is that the Siting Board could determine that "other factors" could outweigh environmental impacts of a proposed facility, but that the Siting Board must include a statement of reasons that includes a determination of each issue of fact or law necessary to the decision (id. at 60, citing, City of New Bedford, 413 Mass at 490).

SCE asserted that the SJC endorsed the standard of review that the Siting Council used in the MASSPOWER Decision and asserted that "this standard fully meets the requirements of the statute"[163] (id. at 61). Thus, SCE argued that the Siting Board should adopt a standard of review similar to that used in the MASSPOWER Decision (id. at 61 through 64). SCE asserted that the elements of such a review, following a finding of need for the proposed project and the superiority of the proposed site, would include identifying the alternative technologies that could be built on the proposed site that could fulfill the need, eliminating any comparison of options that could not meet the need, and then using project-specific and site-specific data to compare the proposed facility with the range of other practical generating alternatives[164] (id., at 62).

ii. The Attorney General's Position

The Attorney General argued that the SJC's decision in City of New Bedford explicitly found that the Siting Board's enabling legislation directs the Siting Board to balance the environmental harm of a new power plant with other statutory objectives of providing a

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163 SCE noted that the MASSPOWER Decision did not require a finding of consistency with current health, environmental protection, and resource use and development policies of the Commonwealth, but that G.L. c. 164, § 69J requires their consideration and urged the Siting Board to make appropriate findings based on the record evidence in this case (SCE Supplemental Brief at 61 through 62, n.28).

164 SCE explained that looking only at those options that can meet the identified need is consistent with G.L. c. 164 § 69J which requires "a description of actions planned to be taken by the applicant to meet future needs or requirements" (SCE Supplemental Brief at 62 through 63). Further, the Company asserted that project-specific comparisons are also consistent with the same section of the statute which requires comparison of alternatives "to the `planned action', i.e., the proposed facility" (id. at 63). In addition, SCE argued that the Siting Board cannot perform its statutorily mandated balancing of reliability, cost and environmental impact without examining the proposed project and alternatives on a site-specific basis (id.).

necessary energy supply at the lowest possible cost (Attorney General Supplemental Brief at 79 through 80). The Attorney General also argued that the SJC found that the Siting Council's past practice of requiring a non-utility applicant to establish that its proposed plant was superior to alternative approaches in terms of cost, environmental impact, reliability and ability to address a demonstrated need comported with the statutory mandate (id. at 80). The Attorney General further argued that the SJC's decision clarified that both utility and non-utility applicants must comply with the statute's requirements (id.). In short, the Attorney General concluded that in all siting cases, "a full comparative review of the environmental consequences, relative benefits, and feasibility of using alternatives to any plant proposed by a developer" must be undertaken (id. at 81).

The Attorney General maintained that G.L. c. 164, § 69I provides that this comparative review requires, among other things, a description of alternatives to the planned action including "no additional electrical power or gas; [and] a reduction of requirements through load management" (id.). The Attorney General also maintained that this section lists additional data which must be provided relative to impacts of the planned action (id.). Relying on the MASSPOWER Decision, the Attorney General explained that a comparison of alternative approaches that are comparable in terms of their ability to meet the established need must first analyze the proposed project's environmental impacts after which the Siting Board "may then balance the adverse environmental harm that would be caused by the new power plant against the other permissible statutory objectives (id. at 82). The plant can then be approved if the Siting Board finds that the impacts from the proposed plant are minimum, or if they are not, that the adverse impacts are outweighed by other permissible goals of the statute (id.).

The Attorney General argued that G.L. c. 164, § 69I requires all project proponents to evaluate the possibility of meeting demonstrated need through means other than new power generation (id.). Thus, the Attorney General argued new power needs first should be measured against available conservation and a non-utility developer should be required to demonstrate that energy savings equivalent to the new capacity that the proposed plant would provide cannot be achieved through conservation and load management ("C&LM")[165] (id. at 82 through 83).

The Attorney General further argued that if C&LM is incapable of meeting the demonstrated need, the Siting Board should then consider a hierarchy of other options (id. at 84). The Attorney General asserted that these other options should commence with renewable resources that are cleaner than fossil fuels, and then proceed through natural gas options and coal gasification options, both of which are superior to the proposed CFB option (id.).

The Attorney General also argued that the Siting Board should require proponents of new facilities to compare the proposed project to real project alternatives, not to generic alternatives (id. at 85 through 88). The Attorney General maintained that, "[i]n most cases, the proponents are sophisticated, experienced actors in the power generation field who have as much knowledge as anybody about the availability and technical details of the full panoply of energy resource options"[166] (id. at 86). The Attorney General also maintained that the Siting Board should not ignore other projects that are currently being reviewed in separate dockets before the Siting Board as examples of other real alternatives (id. at 87 through 88). The Attorney General concluded that "[w]henever a real project exists that can be made the basis for an alternatives comparison, it should be required to be so utilized. In such a situation, a `generic' review should be deemed insufficient per se" (id.).

The Attorney General further argued that the Siting Board, when balancing environmental impacts and cost, should include in the consideration of costs the environmental externality costs found in the Department's Integrated Resource Management ("IRM")

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[165] The Attorney General argued that the fact that a non-utility developer might not be in a position to deliver C&LM should not be an excuse for failing to evaluate C&LM as an alternative to the construction of a new power plant (Attorney General Supplemental Brief at 83 through 84).

[166] The Attorney General also argued that the record in this case shows that the partners of SCE -- CEI, PG&E/Bechtel, and CSC -- have experience in the power generation field and have knowledge regarding the availability and technical details of the full range of energy resource options (Attorney General Supplemental Brief at 86).

regulations (id. at 88 through 94). The Attorney General asserted that in addition to being a part of the total cost of the project, such a comparison would bring consistency to the resource development and resource acquisition phases of providing energy resources[167] (id. at 90). To the extent that non-price criteria must be weighed against considerations of externalities, the Attorney General cited the Siting Council's decision in EFSC 90-RM-100A,[168] for the proposition that considerations of externalities are not to be weighed against non-price criteria (such as fuel diversity) (id. at 92). The Attorney General argued that the principal goal of the IRM regulations is to level the playing field for all participants and competitors in the procurement process (id. at 90 through 91). The Attorney General also argued that G.L. c. 164 does not treat non-utility developers and utilities differently, therefore, the Siting Board should not do so in the siting process (id.). The Attorney General further argued that since the Siting Board has expressed its belief that the IRM process is an efficient process for fulling its statutory mandate, adopting the Department's externalities values for non-utility developers in the siting process would be the most sensible approach for the Siting Board (id. at 93 through 94).

b. Analysis

The approaches suggested by both SCE and the Attorney General relative to the standard of review that should be used by the Siting Board in the comparison of alternative technologies were raised by the parties in the EEC remand proceeding and were analyzed in the decision in that proceeding. See, EEC (remand) Decision, 1 DOMSB at 276-296. In that

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167 The Attorney General acknowledged that the Department's values for externalities only apply to air pollutants and are, therefore, underinclusive (Attorney General Supplemental Brief at 91 through 92). Nevertheless, he argued that the Siting Board should include the values that currently exist and expand coverage to all significant environmental externalities that the Department later monetizes (id. at 92).

168 Rulemaking Regarding the Procedures by Which Additional Resources are Planned, Solicited, and Procured by Investor-Owned Electric Companies (Integrated Resource Management), Final Order on Rulemaking, 21 DOMSC 91 (1990) ("Siting Council IRM Decision").

decision, the Siting Board concluded that with respect to the issue of load management, the analysis of load management as an alternative to the planned activity is not required by statute. Id. at 287. Further the Siting Board concluded that a non-utility developer fulfills its statutory mandate with reference to a consideration of the reduction of requirements through conservation and load management when it complies with the requirement of G.L.c. 164, § 69J, which it does in the analysis of need. Id. In addition, the Siting Board concluded that a description of the alternative of "no additional electric power or gas" when read in context of G.L. c. 164, § 69I makes sense only in regard to a utility's long-range forecast. Id. at 288.

With respect to the Attorney General's suggestion that the Siting Board establish a hierarchy of alternative resource options, the Siting Board concluded that such a hierarchy is likely to elevate environmental impacts over other statutory considerations and, as such, would be inconsistent with statutory construction precepts that require each word of a statute to be given its appropriate effect without emphasizing one at the expense of others. Id. at 289. With respect to the argument by the Attorney General that an analysis of generic technologies is "per se" insufficient to comply with the Siting Board's statutory mandate to compare alternatives, the Siting Board concluded that requiring a review of generic alternatives is an acceptable method at this time to ensure that the minimum impact standard is met.[169] Id. Further the Siting Board concluded that specific real projects that are supported by sufficient information to allow for a complete review by the Siting Board and all parties to the proceeding of its costs, environmental impacts, and reliability to meet an identified need, if presented by a party to the proceeding, may be considered as alternatives to the proposed project. Id. With respect to the argument of the Attorney General concerning environmental externalities, the Siting Board concluded that a comparison of alternatives can be undertaken that comports with our statutory mandate without including the Department's values for air emissions. Id. at 293. Further, the Siting Board concluded that based on the record in that proceeding, it would be inappropriate to apply the Department's environmental externality values in a review of the proposed project.

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169 The Siting Board notes that the fact that CEI, PG&E/Bechtel, and CSC are partners of SCE, does not alter this conclusion.

Id. The Siting Board notes that the record in the present case suggests that the same conclusions should be reached in this proceeding.

Accordingly, after considering the arguments presented by the Company and the Attorney General, and reviewing the Siting Board's determination in the EEC (remand) Decision, the Siting Board finds that the standard of review for the comparison of alternative technologies established in the EEC (remand) Decision continues to be appropriate, and will be applied in this proceeding. That standard is set forth below.

c. Conclusion

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 facilities which operate on the principle of cogeneration or hydrogeneration; and (c) no additional electric power or gas.

In implementing its statutory mandate, the Siting Board requires a petitioner to show that, on balance, its proposed project is superior to alternate approaches in the ability to address the previously identified need in terms of cost, environmental impact and reliability. Cabot Power Decision, 2 DOMSB at 334; Altresco Lynn Decision, 2 DOMSB at 107; EEC (remand) Decision, 1 DOMSB at 296. Additionally, where a non-utility developer proposes to construct a QF facility in Massachusetts, the Siting Board determines whether the project offers power at a cost below the purchasing utility's avoided cost. Cabot Power Decision, 2 DOMSB at 334; Altresco Lynn Decision, 2 DOMSB at 107; EEC (remand) Decision, 1 DOMSB at 296; NEA Decision, 16 DOMSC at 360-380.

2. Identification of Resource Alternatives

To address a need for at least 150 MW of additional energy resources by 1997, SCE proposes to construct a 150 MW CFB boiler cogeneration power plant in Taunton, Massachusetts (Exh. EFSB-AER-2). The Company stated it had not considered a smaller facility because (1) it had concluded in an early phase of project development that the energy that the proposed facility would provide was needed, and (2) it had optimized the size of the planned facility for the proposed site (Exh. EFSB-AER-3; Tr. 27, at 136 through 138).[170]

The Company examined four alternative approaches to address a need of at least 150 MW (Exh. SCE-23, at 2). Selection of the four alternatives was based on criteria of size, reliability, technical maturity, construction time-frame, siting and permitting feasibility, fuel availability, compatibility with cogeneration and non-utility generation, and ability to meet the identified need (id.). SCE identified the following four technologies as constituting reasonable replacements for the proposed project: (1) a natural gas-fired combined cycle combustion turbine ("CTCC") with a firm (i.e., 365-day) supply of gas ("NGCC alternative"); (2) a natural gas-fired CTCC with an oil backup ("GOCC alternative"); (3) a pulverized coal facility ("PC alternative"); and (4) a residual oil-fired facility ("RO alternative") (Exh. SCE-23, at 2). As an alternative to the proposed project, the Attorney General identified a coal gasification combined cycle unit ("CGCC alternative"), which would utilize the Destec coal gasification process (Exh. AG-9). In recent reviews of proposed generating facilities, the Siting Board has considered a similar range of technology alternatives. See, Cabot Power Decision, 2 DOMSB at 334-346; Altresco Lynn Decision, 2 DOMSB at 107-123; Eastern (remand) Decision, 1 DOMSB at 296-299.

The Company indicated that it had not performed detailed resource evaluation studies on renewable energy sources such as, for example, wind, solar-photovoltaic cells, solid waste, and biomass because it did not believe that these energy sources could produce reliable and

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170 The Company stated that it would, for example, consider downsizing the proposed facility in the case of an unavoidable and unacceptable environmental impact, zoning constraint, financial constraint, or technical constraint (Exh. EFSB-AER-3).

economic electricity at the proposed primary site to meet the identified need for new generating capacity of 150 MW (Exhs. EFSB-AER-2; EFSB-AER-3; Tr. 27, at 138 through 154).[171,172] The Company also stated that it could not meet the identified need with a combination of 60 MW generating capacity from an existing gas pipeline extending to the TMLP Cleary substation and additional energy from a supplementary source (Tr. 27, at 152).[173]

The record demonstrates that renewable energy sources such as wind, solar-photovoltaic cells, solid waste, and biomass are typically too small at present to satisfy a need of 150 MW and that it would not be cost-effective or environmentally sound practice to construct multiple facilities at the proposed site or at multiple sites. Although the record also shows that in the next decade it may be possible to meet greater need for generating capacity with such non-conventional technologies, the Siting Board has found that there is a need for at least 150 MW beginning in 2000, and possibly sooner.[174] Therefore, for the purposes of this review, the

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171 The Company asserted that constructing a single large power plant was preferable to constructing several smaller plants of equivalent total capacity (Exh. EFSB-AER-2). The Company asserted that the benefits of constructing one large plant would stem from economies of scale, from heat efficiencies, and from environmental impacts which would likely be avoided by undertaking construction on one plot of land rather than on multiple plots (id.).

172 The Company also asserted that, assuming that 30 MW of renewable resource capacity was constructed at the proposed TEC site, at least 120 MW of additional capacity would have to be constructed elsewhere (Exh. EFSB-AER-2). The Company indicated potential by the year 2005 or 2010 in the 100- to 150-megawatt range from such renewable technologies as fuel cells, compressed air, solar-photovoltaic cells, site-specific tidal power and, to a lesser extent, wind power (Tr. 27, at 162 through 167).

173 The Company stated that, assuming a firm gas supply and energy generation at the 60 MW level, the technology suited to the existing pipeline would most likely be a simple-cycle gas technology -- more peaking and of shorter duration -- rather than the more efficient combined-cycle technology (Tr. 27, at 152).

174 To proceed with the proposed project, SCE must provide signed contracts for 75 percent of project output by 1998. The Siting Board notes that such contracts could demonstrate a need for the proposed project prior to 2000, based on grounds of

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Siting Board finds that such renewable energy resources as wind, solar-photovoltaic cells, solid waste, and biomass are not reasonable alternative approaches to meeting a need of 150 MW in 2000 or earlier and the Siting Board, therefore, does not analyze these approaches.

Accordingly, for the purposes of this review, the Siting Board compares the environmental impacts, cost and reliability of the proposed CFB project to the NGCC, GOCC, CGCC, RO, and PC alternatives.

3. Environmental Impacts

SCE asserted that its proposed project would be comparable from an overall environmental impact perspective to the NGCC, GOCC, RO, and PC alternatives in terms of environmental impacts, and is superior to the CGCC alternative. The Company based this assertion on an analysis of environmental impacts including fuel transportation, air quality, water supply and wastewater, noise, solid waste, and land use.[175] 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" including: (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 facilities which operate on the principle of cogeneration or hydrogeneration; and (c) no additional electric power or gas.

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[174](...continued)
reliability or economic efficiency.

[175] The Company divided its analysis into 13 different categories: fuel transportation; fuel storage; wetlands impacts; land-area requirements; land-use compatibility; air quality; water requirements; wastewater discharge; solid waste; noise impacts; safety considerations; traffic impacts; and visual impacts (Exh. SCE-23, at 2). The Siting Board analysis here follows that of its previous decisions. See, Cabot Power Decision, 2 DOMSB at 337; Altresco Lynn Decision, 2 DOMSB at 111; EEC (remand) Decision, 1 DOMSB at 299.

In implementing its statutory mandate, the Siting Board requires a petitioner to show that, on balance, its proposed project is superior to alternative approaches in the ability to meet the previously identified need in terms of cost, environmental impact and reliability. Cabot Power Decision, 2 DOMSB at 334; Altresco Lynn Decision, 2 DOMSB at 107; EEC (remand) Decision, 1 DOMSB at 296. Additionally, where a non-utility developer proposes to construct a QF facility in Massachusetts, the Siting Board determines whether the project offers power at a cost below the purchasing utility's avoided cost. Cabot Power Decision, 2 DOMSB at 334; Altresco Lynn Decision, 2 DOMSB at 107; EEC (remand) Decision, 1 DOMSB at 296; NEA Decision, 16 DOMSC at 360-380.

a. Fuel Transportation

i. Description

The Company indicated that fuel for the proposed project and technology alternatives could be transported to the property site by rail, pipeline, and/or truck (Exh. SCE-23, at 2 through 4, Table 1). The Company asserted that rail transportation would be preferable because of the proximity of the site to an active rail line and industrial rail spur, whereas pipeline transportation would present more significant environmental impacts from construction (id. at 3). Thus, the Company asserted that the proposed project and the CGCC, PC and RO alternatives, which would rely on rail transportation, would be preferable to the NGCC and GOCC alternatives which would rely primarily on pipeline transportation (id. at 2 through 3; Exh. AG-5-44).

With regard to the proposed project, the Company indicated that it would require one weekly round-trip of an 80-car coal delivery train powered by 4 diesel locomotives (Exh. SCE-3, at III.1-2 through III.1-3, VI.10-2). The Company also indicated that 10 hopper cars for pelletized ash removal would be delivered separately once-a-week, then attached to the empty coal train for departure (id.).[176]

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[176] The Company indicated that for the proposed project, assuming a heat rate of 9,800 (continued...)

The Company indicated that coal would be transported across Massachusetts along the existing Boston & Albany mainline, a section of Amtrak's northeast corridor, and two secondary track segments to a three-mile rail spur to be restored on an existing rail ROW owned by the Massachusetts Executive Office of Transportation and Construction ("MEOTC")[177] and TMLP (Exhs. SCE-3, at VI.10-2; SCE-1, at 6-6). The Company noted that required upgrading of the rail spur would occur within the rail ROW, and that environmental impacts of rail transport would be related to operation rather than construction, and would stem primarily from traffic delay and noise (Exh. SCE-1, at 6-6). The Company indicated that the secondary track sections include 42 grade crossings, including 12 in downtown Taunton, and that the TMLP rail spur includes 6 grade crossings (Exh. EFSB-RR-139, att. B). The Company also provided information on existing train traffic levels on the mainline and secondary track segments, indicating that the addition of train traffic to serve the proposed TEC would represent a small change proportional to existing traffic on the mainline segments, but a more significant change on the secondary line segments (Exh. EFSB-AER-7). See Section III.C.2.a.vii, below.

The Company also indicated that the proposed project would require delivery of 50,000 tpy of limestone by truck for control of SO_2 emissions (Exh. EFSB-AER-10). The Company anticipated that limestone delivery would require eight 25-ton truck-loads per day, five days per week (id.).[178]

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British thermal units per kilowatt hour ("Btu/kwh"), an availability of 85 percent, and annual fuel requirements of 455,338 tons of coal, 4,554 railcar-loads of coal would be required each year (Exh. SCE-23, at Table 1).

177 For ease of discussion, this three-mile rail spur, approximately 1.0 miles of which are owned by MEOTC with the remainder owned by TMLP, will be referenced as the TMLP rail spur.

178 The Company indicated that its projected limestone delivery requirements assume use of 1.6 percent sulfur coal with a calcium-to-sulfur ratio of 2:1, and facility availability of 85 percent (Exh. EFSB-AER-10). The Company also noted that it had originally
(continued…)

With respect to transportation requirements for the PC and RO alternatives, SCE indicated that each would use rail transportation to deliver coal or oil to the facility site (Exh. SCE-23, at 2).[179] In comparing rail transportation of oil and coal, however, the Company stated that, in the event of a spill or other accidental release of transported fuel, oil, which could migrate into soils and groundwater, would cause greater environmental damage than coal, which is inert and easily remediated (Exh. EFSB-AER-9).[180]

With respect to the CGCC alternative, the Company indicated that a CGCC facility would require 3,950 railcar-loads of coal per year, assuming annual fuel requirements of 395,000 tons of coal based on a heat rate of 9,033 Btu/kwh and an availability of 80 percent (Exh. AG-5-44).[181] The Company stated that the CGCC was the only coal-fired technology requiring a firm supply of either natural gas or fuel oil as a backup fuel, with corresponding environmental impacts of transportation (Tr. JH2, at 126 through 129; SCE Supplemental Brief at 96). The Attorney General argued, however, that the CGCC alternative would use fewer

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(…continued)

overestimated its limestone delivery requirements and that its limestone delivery schedule had been adjusted to reflect lowered estimates (id.).

179 The Company stated that (1) the PC alternative would require 4,466 railcar-loads of coal per year, assuming a heat rate of 10,036 Btu/kwh, an availability of 81.4 percent, and annual fuel requirements of 446,554 tons of coal, and (2) the RO alternative would require 3,610 railcar-loads of oil per year, assuming a heat rate of 9,359 Btu/kwh, an availability of 84.7 percent, and annual fuel requirements of 72,200,000 gallons of oil (Exh. SCE-23, at Table 1).

180 The Siting Board notes that, although SCE did not specifically raise the issue of limestone delivery for the PC alternative, in a recent review of a CFB facility by the Siting Board, coal and limestone delivery for the PC alternative were found to have essentially the same impact as delivery of coal and limestone for that proposed CFB facility. EEC (remand) Decision, 1 DOMSB at 303.

181 David L. Breton, testifying for the Attorney General, stated that based on his experience with the Destec gasification process at Destec's Louisiana Gasification Technology, Inc. ("LGTI") facility, availability of a CGCC facility backed with natural gas would range from approximately 92 to 95 percent (Tr. JH2, at 63 through 64).

rail cars for coal delivery than the proposed TEC, and asserted that, in the event that a gas pipeline were required for a backup fuel source, a pipeline lateral could be built within an existing ROW to deliver readily available gas supply, thus avoiding additional environmental impacts (Attorney General Supplemental Brief at 153 through 154).

With regard to the NGCC alternative, the Company stated that construction of natural gas pipeline facilities would be required to transport natural gas on a firm basis to the site (Exh. SCE-23, at 3). In response to a request from the Siting Board, SCE provided a preliminary analysis of the feasibility of delivering gas to the proposed site through existing Algonquin Gas Transmission Company ("Algonquin") and local pipelines (id. at 3, 7 through 9; Exh. EFSB-AER-13). The Company stated that the most favorable route for a gas supply would be from the Algonquin G-1 line, a pipeline with west-to-east flow located in Dighton, Massachusetts to the south of the proposed site, proceeding north and east parallel to an electric transmission line, and then north along a former rail ROW (Exh. SCE-23, at 7, app. B at fig. 1). The Company indicated that construction of this route would involve construction-period disturbance of wetlands along the route and a river crossing (id.). The Attorney General asserted, however, that it was likely that a pipeline could be extended from Algonquin's existing G-1 line to the TEC site along existing utility ROW and existing railroad layout with no new land disturbance (Attorney General Supplemental Brief at 130).[182]

The Company also analyzed the possibility that gas service could be supplied from Algonquin's G-10 pipeline which proceeds north to the east of the proposed site and the Taunton River (id.). The Company stated that a firm gas capacity study conducted by Algonquin had indicated that firm gas could be supplied to the proposed site from the G-10 line either via the Bay State Gas Company ("Bay State") take station at TMLP, or by crossing the Taunton River with a connecting pipeline segment (id. at 7 through 8; Exh. EFSB-AER-

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[182] The Company acknowledged that it would be feasible to deliver gas to the proposed site along a route which followed utility ROW for 7,700 feet, or 57 percent of the total distance, and an existing railroad bed for 5,700 feet, or 43 percent of the total distance (Exh. EFSB-AER-14). The entire route, therefore, would follow either utility ROW or existing railbed, and would cover a total of 13,400 feet, or 2.53 miles (id.).

13). The Company indicated, however, that the river crossing would involve considerable environmental impacts to the river in the vicinity of the pipeline crossing, to river banks, and to wetlands along and bordering the area of pipeline construction (Exh. SCE-23, at 7 through 8). With respect to use of the Bay State take station, the Company indicated that this would require system modifications such as enhancement of compression upstream, construction of a new take station, and construction of a larger connector pipeline to replace the 10-inch connector now extending from the Algonquin G-10 line to the Bay State take station (Exhs. EFSB-AER-13; EFSB-RR-147).[183]

The Company asserted that the logical path for replacing the existing 10-inch connector pipeline with a larger capacity pipeline would be parallel to the existing TMLP pipeline, but that contaminated soils and disturbed wetlands in the vicinity of construction would potentially result (Tr. 26, at 116). The Attorney General asserted, however, that with modification of the existing system and construction of a new pipeline extending along the existing ROW from the Bay State take station to the proposed site, Algonquin could likely supply additional firm gas to the proposed site with no impacts to previously undisturbed land (Attorney General Supplemental Brief at 130).

With regard to the GOCC alternative, the Company stated that transportation of fuel by both pipeline and truck would be required (Exh. SCE-23, at 3 through 4). The Company asserted that, as for the NGCC alternative, extending a gas pipeline to the Algonquin G-1 pipeline from the proposed TEC site was the environmentally preferable option for providing gas supply, but that pipeline construction would involve adverse environmental impacts (id.). The Company added that the GOCC alternative, which utilizes interruptible gas supply with oil

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[183] The Company stated that if the existing 10-inch connector pipeline from Algonquin's G-10 line to the Bay State take station were to be used to supply a facility at the TEC site in addition to present TMLP needs, all spare capacity on the 10-inch pipeline would be required (Exh. EFSB-RR-147). The Company stated that TMLP would, therefore, be prevented from expanding its supply of gas via the existing 10-inch gas pipeline (id.). The Company noted TMLP's stated position that this restriction of its ability to operate on gas, or potentially increase its gas usage, would be unacceptable (id.).

backup, would involve adverse environmental impacts associated with truck delivery of oil for part of the year in addition to impacts associated with gas pipeline construction (id.).

ii. Analysis

With regard to rail transport of coal and limestone to the proposed project, the record demonstrates that the primary site is served by active primary and secondary lines to an inactive rail spur owned by MEOTC and TMLP. The record also demonstrates that one 80-car train with 4 locomotives would travel east across Massachusetts to the TMLP site, that a shorter 10-car train would arrive separately, and that the two trains, combined to form one 90-car train, would depart the site once each week. The arrival of the 80-car coal delivery train, and departure of the combined 90-car train, would occur on the same day, approximately 15 hours apart.

The record also demonstrates that passage along the mainline and secondary track segments over which the coal delivery/ash removal train is routed requires traversing 42 grade crossings along secondary lines between Framingham and the site, including 12 in downtown Taunton. While rail service to the proposed TEC would not significantly change rail traffic levels on mainline track segments, increased traffic would have more significant impacts on the secondary line segments on flow of traffic and emergency services at at-grade crossings including effects of train passage in downtown Taunton. See Section III.C.2.a.vii., below.

The Siting Board also notes that much of the same track was proposed for rail delivery of coal to another coal-fired generator recently reviewed by the Siting Board. See, EEC (remand) Decision, 1 DOMSB at 305. Thus, additional rail traffic to serve the proposed TEC may add to impacts from rail traffic increases anticipated along the same track from other sources.[184]

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184 The Company has also indicated that Taunton City officials have expressed interest in the increased rail service and associated industrial development which might potentially result from restoration of the TMLP rail spur if the proposed project were to be constructed at the primary site (Exh. SCE-13, at 15).

In comparing rail requirements of the CGCC alternative to the proposed project, the record demonstrates that the CGCC alternative would require 13 percent fewer coal cars on an annual basis. The Siting Board notes, however, that the difference in railcar traffic would be felt not in the number of trains arriving and leaving the project site, but in the slight decrease in the number of cars per train.

With respect to impacts of transporting a backup fuel to the site for the CGCC alternative, the record indicates that impacts would vary greatly according to the chosen backup fuel and the chosen method for transporting the backup fuel to the site. Due to this variation, and to the potential variation in the amount of backup fuel needed for the CGCC alternative, impacts of transporting of backup fuel to the site can not be accurately determined. The Siting Board notes, however, that the backup fuel would be a small portion of the total fuel requirements of the CGCC alternative, and that the choice of fuel and method of transportation would most likely be chosen to minimize environmental impacts. The Siting Board also notes that the CGCC alternative, unlike the proposed facility, does not require limestone for the control of SO_2 emissions, thus avoiding impacts associated with vehicular delivery of limestone required for the proposed facility.

Accordingly, based on the foregoing, the Siting Board finds that the CGCC alternative would be minimally preferable to the proposed project with respect to transportation impacts.

With regard to the PC alternative, the record demonstrates that fuel delivery requirements would be similar to the proposed project. Accordingly, based on the foregoing, the Siting Board finds that the PC alternative would be comparable to the proposed project with respect to transportation impacts.

In comparing the RO alternative to the proposed project, the record demonstrates that overall rail traffic would be less for the RO alternative. However, the record also demonstrates that, in the event of accidental spillage, the environmental impacts of oil, which could migrate into soil and groundwater, would be greater than the impacts of an accidental release of coal. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the RO alternative with respect to transportation impacts.

With regard to pipeline delivery of firm natural gas supplies for the NGCC alternative, the record demonstrates that construction of pipeline facilities would be required. The record further demonstrates that the gas supplies would have to be transported by pipeline from the Algonquin G-1 line located to the south of the project site, or from Algonquin's G-10 line, to the east of the project site. Construction could potentially impact river banks, a streambed, and wetlands, and require either local or upstream system modifications. The Siting Board notes, however, that specialized construction techniques as well as route selection and adjustments in pipeline alignment could minimize disturbance. The record also demonstrates that it may be possible to limit environmental impacts to existing utility and rail ROW.

Nevertheless, pipeline transportation could have significant construction-related impacts as well as permanent impacts such as vegetative alteration and tree clearing, depending on the route chosen and the vegetation and terrain along the route. Rail transportation, on the other hand, would not have construction-related impacts, but would have continual impacts over the life of the project, with respect to locomotive noise and potential traffic interruptions along the route. The Siting Board recognizes that such impacts could be mitigated to a certain extent with input from the communities along the route.

Although the record identifies generally the potential construction-related and permanent impacts of pipeline transportation, the record also indicates that these impacts would vary greatly according to the chosen route. Due to this variation, the potential impacts of fuel transportation of the NGCC alternative could be significantly less or significantly greater than the impacts of the proposed project. Therefore, absent route specific information, the record does not allow for an accurate comparison of the likely transportation impacts of the proposed project with the potential but unknown transportation impacts of the NGCC alternative. Accordingly, based on the foregoing, the Siting Board can make no finding regarding the relative transportation impacts of the proposed project and the NGCC alternative.

With regard to the GOCC alternative, the record demonstrates that the primary transportation impacts would relate to construction of pipeline facilities necessary to transport interruptible supplies to the proposed site. As in the case of the NGCC alternative, the potential transportation impacts of use of a virgin pipeline ROW could be significantly greater than the transportation impacts of the proposed project. However, even if the pipeline route followed an existing ROW and impacts were reduced accordingly, due to the oil requirements for the GOCC alternative, the environmental impacts of accidental oil spillage must also be considered. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the GOCC alternative with respect to transportation impacts, irrespective of pipeline route differences.

b. Air Quality

The Company asserted that the overall air quality impacts of the proposed project would be comparable to those of the NGCC, GOCC, RO and PC alternatives, but less than the air quality impacts of the CGCC alternative, which would be more significant than those of all other technologies (SCE Supplemental Brief at 102).

In comparing the air quality impacts of the proposed project and technology alternatives, SCE considered: (1) estimated emission rates of criteria pollutants including SO_2, NOx, CO, PM-10, and VOC; (2) emission rates of CO_2; and (3) the predicted ambient levels of criteria pollutants in relation to the National Ambient Air Quality Standards ("NAAQS") (Exhs. SCE-23, at 10 through 13, App. A, Tables 1 through 6; EFSB-RR-142; EFSB-RR-142A; SCE Supplemental Brief at 115 through 119). In comparing the air quality impacts of the proposed project and the CGCC alternative, the Company also considered the air quality impacts of benzene and hydrogen sulfide ("H_2S") emissions (Exhs. EFSB-RR-142; SCE-6 at 4-10; SCE Supplemental Brief at 120 through 122).

In this section, the Siting Board reviews the comparative emission rates of the proposed project and technology alternatives and the impact of such emissions on ambient air quality.

i. Emission Rates and Impact on Ambient Air Quality

(A) Emission Rates

The Company estimated emission rates of criteria pollutants and CO_2 for the proposed project and the NGCC, GOCC, CGCC, RO and PC technology alternatives in tons per year ("tpy"), assuming (1) generation of 150 MW of electricity; (2) a technology-specific heat rate in Btu/kWh; and (3) emission factors in lb/MMBtu consistent with fuel characteristics and specific control technologies (Exhs. SCE-1, at 6-13; SCE-6, at 2-14; SCE-23, at 10 through 13 and app. A at Table 1; EFSB-RR-142; EFSB-RR-142A).

With regard to the proposed TEC, the Company assumed a heat rate of 9,800 Btu/kWh and emission factors and control technologies consistent with those specified in its Draft Conditional Air Permit (Exhs. AG-5-45; SCE-23 at app. A, Table 1, Table 3, Table 4). See Section III.C.2.a.i., below. See Table 5.

With respect to the NGCC, GOCC, CGCC, RO and PC alternatives, SCE indicated that it assumed heat rates set forth in the 1992 NEPOOL Generation Task Force Report ("GTF"), adjusted to reflect (1) the steam export of the proposed project,[185] and (2) installation and operation of control technology to meet current Best Available Control Technology ("BACT") standards for NOx control (Exhs. SCE-22, at 21 through 23; SCE-23, at app. A, Table 1, Table 3; AG-5-44). SCE indicated that emission factors were based on BACT emission limits for each of the technologies (Exh. SCE-23, at 10 and app. A, Table 3).

For the NGCC and GOCC alternatives, SCE assumed a heat rate of 8,553 Btu/kWh and selective catalytic reduction ("SCR") technology with steam injection for NOx emissions control[186] (id., at 11 and app. A, Tables 1 and 3). The Company also assumed use of very low sulfur oil (0.05 percent sulfur) for SO_2 emissions control for the GOCC alternative (id.). The

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185 SCE indicated that the 1992 GTF assumes stand-alone generating units rather than cogeneration units such as the proposed TEC (Exh. SCE-22, at 22). Therefore, SCE indicated that the 1992 GTF-specified heat rates for the technology alternatives were increased by 1.3 to 1.8 percent to reflect the proposed facility's steam load of 47,000 pounds of steam per hour (id.).

186 The Company stated that the NOx emission rate would be controlled to (1) 6 parts per million ("ppm") for the NGCC alternative, and (2) 17 ppm for the GOCC alternative when firing oil (Exh. SCE-23, at 11).

Company asserted that its calculation of the heat rate for the NGCC alternative was reasonable in that it is comparable to the heat rate of the Altresco Lynn facility (8,600 Btu/kWh), a gas-fired combined-cycle facility recently reviewed by the Siting Board (SCE Supplemental Reply Brief at 58, citing, Exh. EFSB-AER-28).[187]

The Attorney General argued that the Company's own calculations demonstrate that the pollutant emissions of an NGCC facility would be measurably less than those of the proposed project (Attorney General Supplemental Brief at 114 through 117). The Attorney General further argued that the Company overstated the NGCC heat rate, and thus, the emissions advantage of the NGCC alternative would be even greater (id. at 116 through 117). The Attorney General added that the heat rate for a recently reviewed NGCC facility,[188] with adjustments for comparability to the proposed project, would be 7,818 Btu/kWh, 8.6 percent lower than the 8,553 Btu/kWh heat rate assumed by SCE (Exh. SCE-22, att. RLC-36; Attorney General Supplemental Brief at 116 through 117). The Attorney General argued that, given that BACT determinations are driven by technological advances over time, it would be appropriate for the Company to base its comparison on the lower heat rate (Attorney General Brief at 117).

For the CGCC alternative, SCE assumed a heat rate of 9,033 Btu/kWh based on the 1992 GTF (Exh. AG-5-44; SCE Supplemental Brief at 89). The Company asserted that said heat rate was consistent with the historical heat rate of the Destec LGTI demonstration project and the projected heat rate of the Wabash River Coal Gasification Repowering Project ("Wabash") (SCE Supplemental Brief at 89, citing, Exhs. SCE-AG-92; SB-AG-45).[189] The Company provided emission factors based on a BACT determination for a 1600 MW coal gasification combustion turbine project proposed in Martin County, Florida ("Martin project")

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187 See, Altresco Lynn Decision, 2 DOMSB at 1.

188 See, Cabot Power Decision, 2 DOMSB at 241.

189 SCE noted that the heat rate of the Wabash facility will be 8,974 Btu/kWh, without any upward adjustments for consistency with the specific design features of the TEC project (SCE Supplemental Brief at 118, citing, Exh. EFSB-AG-34(a)).

but also provided information indicating that emission factors generally would be lower than those based on the Martin project (Exhs. EFSB-RR-142; AG-RR-44).[190] The Company asserted that steam injection would be the most likely form of NOx control for the CGCC alternative (SCE Supplemental Brief at n.51).[191]

The Attorney General argued that (1) SCE erred in calculating CGCC emissions by overstating the facility heat rate and emission factors, and (2) the CGCC alternative would produce significantly less air emissions than the proposed project (Attorney General Supplemental Brief at 137 through 138).

The Attorney General's witness, Dr. Breton, provided alternative heat rate and emission factor calculations for the CGCC alternative, based on the Destec gasification process (Exh. AG-RR-50). Dr. Breton initially calculated the heat rate for a hypothetical Destec CGCC facility, comparable to the proposed project, to be 9,872 Btu/kWh for a 150 MW CGCC facility and calculated emission factors lower than the emission factors estimated by the Company (Exhs. AG-9, at 10, 12 through 15 and att. D; SCE-23, app. A at Table 3, Table 4; EFSB-RR-142).[192] During the course of the proceeding, Dr. Breton recalculated the heat rate to be 8,774 Btu/kWh for the Destec CGCC technology scaled to 150 MW and using SCE's reported export steam requirement of 47,000 pounds per hour (Exh. AG-RR-50). Dr. Breton

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190 SCE provided emission factors for the CGCC alternative which were lower than the emission factors based on the Martin facility for NOx, SO_2, C0, and VOCs but higher for PM-10 (Exh. AG-5-44). The Company indicated that it assumed distillate oil firing for 30 days but did not specify the basis for these emission factors (id.).

191 The Company also estimated emissions of benzene and H_2S for the CGCC alternative based on an analysis conducted by Destec at its Wabash facility -- although the Company also stated that the benzene emissions in the Wabash analysis may have been based on Destec's experience at LGTI (Exhs. EFSB-RR-142; EFSB-RR-142A; EFSB-RR-142B). For benzene, the Company estimated short-term emission impacts, primarily from the tail gas incinerator and emergency flare, at 1.4 ug/m^3 over an 8-hour averaging period (Exh. EFSB-RR-142). The Company estimated 8-hour emission impacts for H_2S at 14 ug/m^3 (id.). See Section II.B.3.b.i.(B)(2), below.

192 The Attorney General also provided the permitted emission factors for the Wabash facility (Exh. JH-RR-1). See Table 6.

noted that such a decrease in heat rate would further decrease annual fuel requirements, and that as fuel requirements decrease, the annual amount of the pollutants emitted also decreases (Exh. AG-9, att. D; Tr. JH3, at 24 through 25, 43).

With regard to heat rate calculations, SCE responded that no coal gasification facility has operated at a heat rate comparable to the heat rate calculated by Dr. Breton (SCE Supplemental Brief at 89, citing, Exh. SCE-AG-106). The Company questioned the computer simulation model which Dr. Breton used to produce a heat rate of 8,774 Btu/kWh and stated that Dr. Breton's calculations assumed pressures and turbine sizes that were not comparable to the proposed TEC and failed to take into account project-specific environmental mitigation (id. at 89; SCE Supplemental Reply Brief at 65 through 66).

With regard to emission factors, the Company responded that in order to compare emissions of the CGCC alternative with the proposed TEC, it was appropriate to utilize permitted levels for a CGCC facility rather than the calculated emission factors for a hypothetical CGCC facility, as proposed by the Attorney General (id. at 64).

With respect to the RO alternative, the Company assumed: (1) a heat rate of 9,359 Btu/kWh; (2) use of oil with a one percent sulfur content and a dry scrubber for SO_2 emissions control; and (3) SCR or selective non-catalytic reduction technology ("SNCR") for NOx control (Exh. SCE-23, at app. A, Table 1, Table 3). Finally, with respect to the PC alternative, the Company assumed: (1) a heat rate of 10,036 Btu/kWh; (2) use of 1.8 percent sulfur coal and a dry scrubber for SO_2 emissions control; and (3) SCR or SNCR for NOx control (id.).

The Company also provided estimated annual CO_2 emissions for the proposed TEC, and the NGCC, CGCC and PC alternatives (Exhs. AG-RR-13; EFSC-E-10). See Table 5.

In sum, in comparing the natural gas-fired alternatives to the proposed project, SCE indicated that the NGCC and GOCC alternatives would have lower emissions for all pollutants (Exh. EFSB-RR-142A, Table 3, Table 4). In comparing the CGCC alternative to the proposed project, the Company indicated that, based on the Martin project, and adjusting for emissions from a 150 MW facility, the CGCC alternative would have lower emissions for CO and PM-10 and higher emissions for NOx, SO_2 and VOCs (id.). In comparing the RO alternative to the proposed project, the Company indicated that the RO alternative would have lower emissions for SO_2, CO and VOC and comparable emissions for NOx and PM-10 (id.). In comparing the PC alternative to the proposed project, the Company indicated that the PC alternative would have lower emissions for CO, but comparable or higher emissions for other pollutants (id.).

(B) Impact of Emissions

(1) Criteria Pollutants

With respect to criteria pollutants, SCE asserted that the air quality impacts of the proposed project, and the NGCC, GOCC, CGCC, PC, and RO alternatives would be minimal and comparable and would not adversely affect air quality (Exhs. SCE-23, at 12 through 13; EFSB-RR-142; SCE Supplemental Brief at 103 through 115). To predict the impact of criteria pollutant emissions on air quality, the Company estimated the percentage of the NAAQS that each facility's emissions would constitute for SO_2, NOx, CO and PM-10 (Exhs. SCE-23, Table 5, Table 6; EFSB-RR-142A; Tr. 26, at 19 through 20). For the proposed project and each technology alternative, the Company stated that the emissions of each pollutant would constitute an extremely small contribution to ambient concentrations of that pollutant, expressed as a percentage of NAAQS (Exhs. SCE-23, at 12, Table 5, Table 6; EFSB-RR-142A).

With respect to the proposed project, SCE based air quality impacts on the results of the detailed modeling analysis that was performed in support of its air permit application (Exhs. SCE-23, at 12; SCE-6, at 6-1 through 6-39). For the NGCC, GOCC, CGCC, PC and RO alternatives, the Company provided a screening level analysis which compared modeled emissions impacts of each of the various alternative technologies to the NAAQS levels for relevant measurement periods (Exhs. SCE-23, at 12 and app. A, Table 5, Table 6; EFSB-RR-142). See Table 7.

In comparing the NGCC alternative to the proposed project, the Company's analysis demonstrated that impacts for all criteria pollutants for all averaging periods, with the exception of annual NOx impacts, would be less for the NGCC alternative and that annual NOx impacts would be comparable for both technologies (Exh. SCE-23, App. A, Table 6).

In comparing the GOCC alternative to the proposed project, the Company's analysis demonstrated that impacts for all criteria pollutants for all averaging periods, with the exception of annual NOx and SO_2 impacts would be less for the GOCC alternative while annual NOx and SO_2 impacts would be less for the proposed project (id. at Table 5).

In comparing the CGCC alternative to the proposed project, SCE's analysis demonstrated that impacts for SO_2 and NOx for all averaging periods would be greater for the CGCC alternative and impacts for PM-10 and CO for all averaging periods would be greater for the proposed project (Exh. EFSB-RR-142S at Table 5).[193]

In comparing the PC and RO alternatives to the proposed project, the Company's analysis demonstrated that impacts for NOx and SO_2 for all averaging periods would be greater for the PC and RO alternatives and that impacts for CO and PM-10 for all averaging periods would be greater for the proposed project (Exh. SCE-23, App. A, Table 5).

(2) Other Pollutants

SCE asserted that the impacts of CO_2 emissions from the proposed project would be comparable to the CGCC, NGCC, GOCC, PC and RO alternatives (SCE Supplemental Brief at 115). However, SCE also asserted that the CGCC alternative would likely have an adverse air quality impact with respect to emissions of benzene and H_2S (id. at 120 through 121).

With respect to CO_2, SCE asserted that although CO_2 emissions of the proposed project essentially would be equivalent to emissions of the CGCC, PC and RO alternatives and greater than emissions of the two natural gas-fired alternatives, relative CO_2 emissions impacts of the technology alternatives are not represented by the numerical differences in total emissions (id. at 115). The Company asserted that because there is no ambient air quality standard for CO_2 emissions and no specific information regarding the contribution of CO_2 emissions to

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193 The comparison was based on the CGCC data provided by the Company, based on the Martin project. See Table 6, Table 7.

overall long-term atmospheric and climatic conditions, a mere comparison of the total amount of CO_2 emissions of the various technologies does not result in a meaningful analysis of their relative CO_2 impacts (id. at 115 through 116). In addition, the Company noted that the CO_2 emission increment resulting from operation of the proposed project after NEPOOL backout would be only 26 percent of its total CO_2 emissions (see Section II.A.4.e, above), and that with the direct emissions offsets proposed consistent with those required by the Siting Board in the Eastern Energy Corporation , 25 DOMSC 296, 367-368 ("1992") ("EEC Compliance Decision"), the net emissions of the proposed project would be further reduced (id. at 138). See Section III.C.2.a.i., below.

With respect to emissions of H_2S and benzene, the Company stated that the proposed project would emit negligible quantities of H_2S and that benzene emissions would be below Massachusetts Department of Environmental Protection ("MDEP") established (1) 24-hour threshold effects exposure limits ("TEL"), and (2) annual allowable ambient limits ("AAL") (Exhs. SCE-6, at 4-10; EFSB-RR-142, at 2).

For the CGCC alternative, the Company calculated likely H_2S and benzene concentrations based on the concentrations and emission rates included in the permit application for the proposed Wabash facility (Exhs. HO-RR-142; SCE-AG-51).[194] SCE stated that the results of its analysis demonstrated that the 24-hour average benzene and H_2S concentrations would exceed the TEL and that the one-hour average H_2S concentration also would exceed thresholds for noticeable odor (Exh. EFSB-RR-142).

With regard to the Company's assertion that TELs would be exceeded for benzene and H_2S emissions, Dr. Breton responded that, for both pollutants, emissions estimates for the Wabash facility were based on site specific information which would not necessarily be

[194] In estimating benzene and H_2S emissions from the CGCC alternative, SCE scaled the results of a modeling analysis for the proposed 265 MW Destec Wabash facility to account for the differences in plant sizes, assumed annual plant availability and appropriate averaging periods (Exhs. EFSB-RR-142; EFSB-RR-142B; SCE-AG-51). In estimating such emissions, SCE added potential emissions from the stack for the combined-cycle unit, tail gas incinerator and flare, and also fugitive sources (id.).

accurate for other locations (Exhs. EFSB-RR-142; EFSB-RR-173; SCE-AG-51; Attorney General Supplemental Brief at 143 through 144). Further, Dr. Breton stated that SCE overstated estimated fugitive H_2S emissions based on fugitive H_2S emission estimates for the Wabash facility (Exh. EFSB-RR-173). He noted that the estimates for the Wabash facility did not take into account mitigation measures that would be implemented to control or eliminate fugitive emission sources (id.).

The Company responded that it had scaled-down H_2S and benzene emissions from the Wabash facility, contrary to the Attorney General claim that the Company had scaled-up the emissions (SCE Supplemental Reply Brief at 67, citing, Exh. EFSB-RR-142). The Company further indicated that since the H_2S and benzene emissions predicted for a CGCC facility were based on data derived from predicted emissions at the Wabash facility, they were, therefore, a reasonable indicator of the likely emissions of a CGCC facility at the proposed site (id. at 67, 69, citing, Exh. EFSB-RR-142). In addition, SCE noted that H_2S emissions from all sources at the Wabash facility were added in submitting emissions data to the state permitting agencies (id. at 67).

ii. Analysis

The Company and the Attorney General differed in their approaches to analyzing air quality impacts. Therefore, we must first discuss the framework for analyzing air quality impacts in our review. The Company asserted that the air quality impacts of the various technology alternatives should be evaluated by comparing the emissions impacts of the technology alternatives to the relevant ambient standards and not, as suggested by the Attorney General, by a mere comparison of the quantity of substances emitted (Exh. SCE-23, at 10 through 12; SCE Supplemental Reply Brief at 54).

The Attorney General argued that SCE has overemphasized its reliance on the predicted air quality levels as a percentage of ambient standards and that the central question in comparing air quality impacts is, instead, the minimization of impacts (Attorney General Brief at 118 through 121). First, the Attorney General argued that while the NAAQS are a regulatory standard focusing primarily on local health effects which is an important issue, the environmental policies of the Commonwealth and the nation also are concerned with pollution over a broader area as well as the cumulative effects of emissions on air quality (id. at 118 through 119). Second, the Attorney General argued that all effects of pollutant emissions, such as acid deposition, are not addressed by the NAAQS and, in addition, the NAAQS do not cover certain pollutants such as CO_2 (id. at 119). Next, the Attorney General argued that the BACT process is not dependent on established regulations, but instead is a technology-driven process to find the best way to minimize emissions from a given fuel and technology (id. at 119 through 120). The Attorney General further argued that Siting Board review is not limited to a review of standards imposed by other agencies in that such standards do not necessarily guarantee that a project's environmental impacts have been minimized (id. at 120).[195]

The Attorney General also argued that the Company did not measure impacts on the NAAQS in a consistent manner for the proposed project and the technology alternatives in that a refined modeling analysis was performed for the proposed project while only a screening level analysis was performed for the alternatives (id. at 120 through 121). The Attorney General further argued that, although the screening level analysis may signal potential problems, refined modeling may dispose of all or most of the violations identified under the screening level approach (id.).

SCE responded that the central issue is not minimization of a facility's emissions, but instead, minimum impact on the environment (SCE Supplemental Reply Brief at 57). The Company asserted that an exclusive focus on the quantity of emissions avoids any analysis of air quality impacts and that the NAAQS offer the clearest standard of measuring the impact on the environment for most air emissions (id.).

In comparing the relative air quality impacts of the various technologies, the Siting Board recognizes the significance of considering the impact on local ambient air quality by

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195 In addition, the Attorney General argued that environmental externalities are valued by the Department in tpy and not on the basis of on-ground impacts of specific facilities (Attorney General Brief at 120).

looking at the percentage of NAAQS that each technology would consume. However, this methodology represents a threshold for comparing air quality impacts. If emissions from a specific technology alternative increased the ambient levels of a pollutant to a level close to, or above, allowable standards, or consumed a significant proportion of allowable standards, the air quality impact of such technology alternative likely would be deemed unacceptable. Here, emissions from all technology alternatives comply with NAAQS by substantial margins. Therefore, the Siting Board's comparison of air quality impacts must encompass more than a review of compliance with the NAAQS.[196] See, EEC (remand) Decision, 1 DOMSB at 321-322.

In addition, the Siting Board has concerns regarding the Company's reliance on an analysis of relative air quality impacts as a percentage of NAAQS. First, the Attorney General correctly states that all impacts of pollutant emissions simply are not addressed by the NAAQS, including (1) the impact of CO_2 emissions, and (2) the effect of criteria pollutant emissions on air quality concerns that are regional or global in nature.[197] Second, the Company's analysis presents the proposed project in isolation relative to ambient standards, and thus ignores the cumulative impact of additional emissions sources that are likely to be constructed in the local area within the 30-year horizon of facility operation. Nevertheless, the Siting Board is sensitive

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196 In the EEC Decision the Siting Board recognized that Federal and state regulations generally establish quantitative or other specific requirements of acceptability for particular environmental impacts and that compliance with these thresholds does not establish that a facility's environmental impacts have been minimized. 22 DOMSC at 334.

197 The Siting Board notes that SO_2 and NOx emissions contribute to acid rain and that NOx and VOC emissions contribute to the formation of ground level ozone. The Siting Board further notes that acid rain is deposited in regions that extend beyond the local area of the point source and that ground level ozone also is transported to regions that extend beyond the local area of the point source.

to the Company's position that raw emission data do not translate directly into environmental impacts.[198]

In sum, a comparison of the percent of ambient standards consumed by each technology alternative's contribution to ambient concentrations does provide a context for comparing relative air quality impacts.[199] However, a comparison of the pollutants emitted also provides a reasonable and broader basis for comparing technologies. Therefore, the Siting Board considers both (1) the total amount of pollutants emitted and, (2) impacts to local air quality as appropriate measures to compare overall air quality impacts. See, EEC (remand) Decision, 1 DOMSB at 322-323.

In comparing the NGCC alternative to the proposed project, the record demonstrates that emissions of criteria pollutants and CO_2, would be significantly less for the NGCC alternative.[200] In addition, potential improvement in the NGCC heat rate would serve to further reduce facility emissions, thereby increasing the advantage of the NGCC alternative. The record further demonstrates that although the contribution of both the proposed project and the

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198 The Siting Board recognizes the Attorney General's concern regarding the consistency of the Company's methodology for analyzing ambient impacts for the proposed project and technology alternatives, in that the Company provided a refined analysis for the proposed facility but a screening-level analysis for the technology alternatives. However, the Siting Board notes that a refined analysis for a technology alternative is an unrealistic requirement to place on a proponent in the context of a comparative technology review.

199 The Siting Board rejects the Company's assertion that air quality impacts are comparable where the contribution to ambient concentrations from the various technology alternatives differ, but are small relative to the NAAQS. A technology alternative that consumes a smaller percentage of the NAAQS for all pollutants would have less environmental impact with respect to air quality, even where differences between technologies are small. See, EEC (remand) Decision, 1 DOMSB at n.156.

200 The record demonstrates that, compared to the proposed project, the NGCC alternative would emit approximately: (1) 13 percent of the NOx emissions; (2) 2.1 percent of the SO_2 emissions; (3) 14.5 percent of the CO emissions; (4) 35.3 percent of the VOC emissions; (5) 16.7 percent of the particulate emissions; and (6) 56 percent of the CO_2 emissions (Exh. SCE-23, App. A, Table 4).

NGCC alternative to ambient concentrations would constitute a minimal percentage of ambient standards, ambient impacts nonetheless would be less for the NGCC alternative. Accordingly, based on the foregoing, the Siting Board finds that the air quality impacts of the NGCC alternative would be preferable to the air quality impacts of the proposed project.

In comparing the GOCC alternative to the proposed project, the record demonstrates that although emissions would be slightly higher than emissions of the NGCC alternative, emissions of the GOCC alternative for criteria pollutants also would be significantly less than emissions from the proposed project.[201] In addition, the Siting Board notes that there also could be potential improvement in the GOCC heat rate, increasing the advantage of the GOCC alternative. With respect to ambient impacts, the record demonstrates that ambient impacts of the GOCC alternative would be less for 3-hour and 24-hour SO_2 standards, CO and PM-10, but would be greater for annual NOx and SO_2 standards. Accordingly, based on the foregoing, the Siting Board finds that the air quality impacts of the GOCC alternative would be preferable to the air quality impacts of the proposed project.

In comparing the CGCC alternative to the proposed project, the Company and the Attorney General presented varying estimates of facility emissions. The Company provided emissions factors based on a BACT determination for a CGCC facility and an alternative set of emission factors which were generally lower. The Attorney General provided emission factors based on a hypothetical CGCC facility and also provided the permitted emission factors for another CGCC facility.

The Siting Board notes that expected emissions for a facility are likely to be less than permitted emission rates in order to ensure that permitted levels are not exceeded. The emission factors provided by the Company for the proposed project were the emission rates contained in its draft air permit, and therefore, the Siting Board agrees with the Company that it

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[201] The record demonstrates that compared to the proposed facility, the GOCC alternative would emit approximately: (1) 18 percent of the NOx emissions; (2) 5.4 percent of the SO_2 emissions; (3) 18.8 percent of the CO emissions; (4) 50 percent of the VOC emissions; and (5) 49 percent of the PM-10 emissions (Exh. SCE-23, App. A, Table 4).

is appropriate to compare these emissions to the permitted emission rates for a CGCC facility. However, the record contains a wide range of emission rates based on permit levels for two CGCC facilities. The permit emission rates for the Martin facility are generally greater than those for the proposed facility while the permit emission rates for the Wabash facility are generally lower than those for the proposed facility. See Table 6. In addition, the Company provided an alternative set of CGCC emission rates which were generally lower than those based on the permits for both facilities and the proposed TEC. Thus, emission factors potentially would be less for the CGCC alternative than the proposed facility.

However, even though emission factors for certain criteria pollutants potentially would be less for the CGCC alternative, a significant concern with the CGCC technology is potential emissions of H_2S and benzene. The record demonstrates that emissions of benzene and H_2S from the CGCC alternative could potentially exceed Massachusetts established standards. Therefore, on balance, the Siting Board finds that the proposed project would be preferable to the CGCC alternative with respect to air quality.

In comparing the PC alternative to the proposed project, the record demonstrates that emission rates of the PC alternative would be greater for NOx and SO_2, comparable for VOC and PM-10 and less for CO. In addition, ambient impacts of the PC alternative would be greater for NOx and SO_2 and less for CO and PM-10. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be comparable to the PC alternative with respect to air quality.

In comparing the RO alternative to the proposed project, the record demonstrates that emission rates of the RO alternative would be comparable for NOx and PM-10, and less for SO_2, CO and VOCs. In addition, the ambient impacts of the RO alternative would be greater for NOx and SO_2 and less for CO and PM-10. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be comparable to the RO alternative with respect to air quality.

c. Water Supply and Wastewater

i. Water Supply

(A) Description

The Company indicated that large quantities of Taunton River water would be required for each of the technology alternatives, primarily for cooling water makeup and minor miscellaneous uses, with lesser quantities of water required from the City of Taunton municipal water supply for boiler feedwater and potable water (Exhs. SCE-4, app. C at 3; AG-5-40, Table 7). SCE asserted that the water supply impacts of the proposed TEC and the NGCC, GOCC, CGCC, PC, and RO alternatives are not substantially different and thus would be comparable (Exhs. SCE-23, at 13 through 14; AG-5-40, Table 7).

With respect to the proposed project, SCE stated that water supply requirements have been minimized by facility design including (1) use of a single reheat boiler, and (2) a range of water conservation measures (Exh. SCE-5, at 2-2 through 2-3; SCE-3, at VI.14-2). The Company estimated that the proposed project would require 2.31 Million Gallons per Day ("MGD") from the Taunton River, 2.28 MGD of this total for cooling tower makeup (Exh. SCE-23, at 14). For process water makeup, the Company estimated that 0.08 MGD would be required from the City of Taunton water supply (id.). The Company stated that total consumptive water use for the proposed project would be 1.94 MGD (Exh. AG-5-40, Table 7).[202] See Section III.C.2.a.iii, below.

In estimating the water supply requirements for the PC and RO alternatives, the Company stated that the same conservation techniques as for the proposed TEC could be incorporated, but that the PC and RO alternatives would consume SO_2 scrubber makeup water not required by the proposed TEC, such that their total consumptive water use would be 1.97 MGD, or .03 MGD higher than for the proposed project (id.). See Table 8.

The Company stated that the NGCC and GOCC alternatives would use less water from the Taunton River but more water from the City of Taunton municipal water supply, relative to

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202 Consumptive water use refers to that portion of total water use that is not returned as wastewater, due, for example, to evaporative losses or removal of solid waste.

the proposed project. See Table 8. The Company added that while the NGCC and GOCC alternatives would incorporate some of the water conservation techniques of the proposed TEC, the amount of city water consumed by these alternatives would not be significantly reduced by such measures (id.).[203,204] The Company stated that it assumed the use of a conventional combustor with steam injection for NOx control and as such, consumptive use of city water by the natural gas-fired alternatives would be almost four times that of the proposed TEC (Exh. EFSB-AER-17). However, the Company added that assuming a dry combustor, this ratio would decrease to about 1.3-to-1 (EFSB-AER-17).[205]

With respect to the CGCC alternative, the Company stated that approximately the same amount of Taunton River water, 1.15 MGD, would be required as for the NGCC and GOCC alternatives, primarily for cooling tower makeup but that an additional 0.14 MGD would be needed for coal slurry makeup water (Exh. AG-5-40). The Company estimated city water use for the CGCC alternative at 0.36 MGD (id.). See Table 8.

The Company asserted that although total and consumptive water uses of the proposed TEC, PC, RO, and CGCC alternatives would differ, the differences in water use rates for the

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203 The Company stated that city water would be necessary for the process water used by the NGCC and GOCC alternatives because the water must be free of all dissolved and suspended solids, and that even city water must be further treated in a demineralizer before use (Exh. AG-5-41).

204 The Company stated that recycling of boiler blowdown and water from equipment drains would save about 40,000 gallons per day ("gpd") of city water, reducing water usage for the NGCC and GOCC alternatives from 300,000 gpd and 320,000 gpd to 260,000 gpd (.26 MGD) and 280,000 gpd (.28 MGD), respectively (Exh. AG-5-40, Table 7).

205 The Company stated that a conventional combuster with steam injection would limit NOx emissions to 9 ppm, consistent with Northeast States for Coordinated Air Use Management ("NESCAUM") guidance for permitting new combustion turbines (Exh. EFSB-AER-5). The Company stated that conventional combustor technology had lower capital and operating costs than dry low-NOx combustors but that dry low-NOx would reduce annual city water requirements for the (1) NGCC alternative by 245,000 gpd and (2) GOCC alternative by 214,000 gpd (id.). In addition, the Company stated that dry low-NOx technology would increase VOC emissions (id.).

various alternatives were less important from an environmental impact perspective than an examination of the type and quality of water used by the various technologies (SCE Supplemental Reply Brief at 125 through 126).

Specifically, the Company noted that the proposed TEC and the PC and RO alternatives would use substantially more river water than the NGCC, GOCC, and CGCC alternatives, but that the proposed facility would use less city water than the NGCC, GOCC, PC, RO, or CGCC alternatives (id. at 126).[206] The Company asserted that city water has higher environmental value than Taunton River water (id.). The Company argued that city water would have higher value because of its greater cleanliness and its origin higher in the watershed than Taunton River water (Exh. EFSB-AER-17).

With respect to Taunton River water use, the Company argued that its analysis demonstrated that the proposed TEC's water withdrawal from the Taunton River would be within the river's estimated safe yield as required under M.G.L. c. 21G, the Water Management Act, for obtaining a water withdrawal permit and that the fact that the proposed TEC would meet such permitting standards supported SCE's assertion that consumptive use of river water would have no adverse impact on the environment (id.; Exh. SCE-23, app. E; Tr. 30, at 7 through 11). The Company asserted that because the proposed river water use of the analyzed technology alternatives would be the same or less than that of the proposed TEC, these facilities would also qualify for a 21G water withdrawal permit and, therefore, would be essentially comparable to the proposed TEC with respect to river water use (Tr. 30, at 7 through 11).

The Company argued, in summary, that the overall water analysis rested on the relative use of city and river water by the various alternatives. The Company asserted that because all the alternatives would operate within the Taunton River's safe yield, and because

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206 The Company stated that the gas-fired alternatives would use over three times the city water requirements of the proposed TEC, and that the CGCC alternative would use more than five times the city water requirements of the proposed TEC (SCE Supplemental Reply Brief at 126).

the proposed TEC would have the lowest city water demand of any of the alternatives, the overall water use of the TEC, therefore, would be comparable to the alternatives in terms of environmental impact (SCE Supplemental Brief at 128).

In response, the Attorney General asserted that the Company had not presented a sound methodology for determining how the Siting Board should weigh the relative non-economic benefits and detriments of city water use against those of Taunton River water use (Attorney General Supplemental Brief at 127 through 128; Tr. 30, at 8 through 11).

The Attorney General argued that the Company overstated the water requirements of the NGCC alternative because, contrary to SCE's assumption, dry low-NOx burners could be used in place of steam injection to control NOx emissions from NGCC facilities (Exhs. EFSB-RR-142A, Table 3; JH-RR-7, att. 1; Attorney General Supplemental Brief at 128). The Attorney General estimated that process water use for the NGCC alternative could thus be reduced from 300,000 gpd to about 55,000 gpd, 25,000 gpd (or 31 percent) less than the 80,000 gpd of process water required by the proposed TEC (Exh. EFSB-AER-5). The Attorney General asserted that since the reduction in the process water requirements of the NGCC alternative would result in a decrease in its city water use to a level below that of the proposed TEC, the claimed advantage of the proposed facility with respect to water use would no longer apply (Attorney General Supplemental Brief at 129). The Attorney General argued that water requirements for the gas-fired alternatives and the CGCC option had been similarly overestimated by the Company and that use of dry low-NOx technology would reduce process water requirements such that the claimed advantage of the proposed facility with respect to water use would no longer apply (Exhs. AG-5-40; EFSB-RR-155; Tr. JH2, at 114 through 116; Attorney General Supplemental Brief at 155 through 157).

(B) <u>Analysis</u>

The record demonstrates that the total and consumptive water use of the proposed TEC, including both Taunton River withdrawals and city water use, would be significantly less than that of the PC and RO alternatives. Accordingly, based on the foregoing, the Siting

Board finds that the proposed project would be preferable to the PC and RO alternatives with respect to water supply.

With respect to the gas-fired combined cycle technologies, i.e., the NGCC, GOCC, and CGCC alternatives, the record demonstrates that total water use, Taunton River water use, and consumptive water use would be greater for the proposed TEC than for the NGCC, GOCC, and CGCC alternatives, but that city water use would be lower for the proposed TEC.

With respect to the value of city water use versus use of Taunton River water, the record provides no sound basis, economic or otherwise, for examination of the relative worth of these two very different sources of water supply. Thus, while the proposed facility likely will use less city water than will the NGCC and GOCC alternatives, the record provides no grounds for valuing the proposed TEC's savings in city water above the savings in Taunton River water use offered by the NGCC and GOCC alternatives. Accordingly, based on the foregoing, the Siting Board finds that the NGCC and GOCC alternatives would be preferable to the proposed TEC with respect to overall water supply impacts.[207]

With respect to the CGCC alternative, the Siting Board notes that total water use would be .18-to-.20 MGD more than that for the NGCC and GOCC alternatives, the other two gas-fired combined cycle options. However, while the water savings offered by the CGCC alternative over the proposed TEC would be less substantial than those offered by the NGCC or GOCC options, total water use for the CGCC option would still be .74 MGD less than for the proposed TEC. Accordingly, based on the foregoing, the Siting Board finds that the CGCC alternative would be preferable to the proposed TEC with respect to water supply impacts.

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207 Further, the Siting Board notes that there is significant variation in the overall water requirements of the NGCC and GOCC alternatives, depending on the choice of NOx control -- steam injection with SCR or dry low-NOx technology. Given the possibility that dry low-NOx technology would be the NOx control technology for the NGCC or the GOCC option at the proposed site, the city water requirements of the NGCC and GOCC alternatives may be substantially lower than the Company's adjusted estimates of .26 MGD and .28 MGD for the NGCC and GOCC alternatives, respectively.

ii. Wastewater

(A) Description

The Company indicated that the proposed project would have a total wastewaster discharge of 448,520 gpd, made up of 433,400 gpd of cooling tower discharge and 15,120 gpd of process water discharge (Exh. AG-5-40; Attorney General Supplemental Brief at 127)

The Company indicated that the wastewater generated by the proposed project and the NGCC, GOCC, RO, PC, and CGCC alternatives would primarily consist of cooling tower blowdown and process wastewater discharge, as well as possibly contaminated stormwater discharges (Exhs. SCE-23, at 16; AG-5-40). The Company stated that all of the alternatives would use the sewer system of the City of Taunton for minimal quantities of domestic sewage, and that stormwater impacts for the NGCC and PC alternatives would be roughly equivalent (id.). The Company asserted that the stormwater impacts for the CGCC alternative might be somewhat greater due to the larger developed area required for that technology (id.). SCE also stated that the oil storage requirements under the GOCC and RO alternatives might result in greater stormwater related impacts (id.).

With respect to the proposed project, SCE stated that wastewater flows would be minimized to the extent possible through a variety of measures, including compliance with the City of Taunton's Infiltration/Inflow program for wastewater reduction and the use of low flow plumbing fixtures at the facility (Exh. SCE-3, at VI.14-3 through VI.14-4). The Company stated that stormwater management practices would ensure that runoff peak discharges after development of the proposed TEC would be approximately the same as pre-development discharges (Exh. SCE-7, at 23). See Section III.C.2.a.iii, below.

In estimating the total quantity of wastewater, the Company stated that the combined-cycle technologies, i.e., the NGCC, GOCC, and CGCC alternatives, would generate somewhat less wastewater than the proposed TEC and the other facilities, while the PC and RO alternatives would generate more wastewater than the proposed facility (SCE Supplemental Brief at 129). See Table 8. The Company also presented a list of pollutants likely to be added to the Taunton River with wastewater discharge from the proposed project and from each of the evaluated alternatives (Exh. EFSB-AER-19). The Company stated that while a comparison of the expected discharges to the Taunton River from the various alternatives indicated that the NGCC, GOCC, and CGCC options would have somewhat less impact than the proposed TEC, the fact that the proposed TEC had received a draft National Pollutant Discharge Elimination System ("NPDES") permit demonstrated that the water quality of the Taunton River would be protected (Exhs. EFSB-AER-18; EFSB-AER-19).

The Company asserted that a comparison of alternative technologies with respect to wastewater should focus on environmental impacts of wastewater generated by the alternatives (id.). The Company also asserted that wastewater discharge impacts of the proposed facility and of the evaluated alternative technologies were comparable because each would have no adverse impact on the environment (Exhs. SCE-23, at 16; AG-5-40; EFSB-AER-18).

The Attorney General noted that, based on evidence presented by SCE, the NGCC alternative would discharge cooling water at the rate of 216,720 gpd and process water at the rate of 93,000 gpd, for a total discharge of 309,720 gpd, significantly less wastewater -- by 138,800 gpd -- than would be discharged by the proposed TEC (Exh. AG-5-40; Attorney General Supplemental Brief at 127). With respect to wastewater discharge of the CGCC alternative, the Attorney General stated that, based on the Company's estimates, a CGCC facility would discharge 416,720 gpd, or 31,800 gpd less wastewater, than the 448,520 gpd wastewater that would be discharged by the proposed facility (Attorney General Supplemental Brief at 155; Exh. AG-5-40). In comparing the proposed facility and the NGCC, GOCC, and CGCC alternatives, the Attorney General argued that the lesser discharges of the three alternatives rendered them superior to the proposed TEC with respect to wastewater impacts.

(B) Analysis

The record demonstrates that the total wastewater discharge of the proposed TEC would be significantly less than that of the PC and RO alternatives, but would be greater than that of the CGCC alternative, and significantly greater than that of either the NGCC or GOCC alternatives.

The Siting Board notes the Company's assertion that the proposed TEC and the evaluated alternatives would not have an adverse impact on the environment with respect to wastewater impacts. The Company has failed, however, to distinguish between compliance with requirements under the NPDES permitting program and consistency with the Siting Board's requirement that wastewater impacts be minimized. The Company has submitted data regarding the concentrations of various pollutants that can be expected in wastewater discharges from the proposed TEC and the evaluated alternatives. The addition of these pollutants to the Taunton River, while well within the standard established by federal legislation, potentially results in adverse impacts on the riverway, with greater undesirable impact resulting from greater quantities and concentrations of discharged pollutants.

Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the PC and RO alternatives with respect to wastewater impacts. The Siting Board finds, in addition, based on the foregoing, that the NGCC, GOCC, and CGCC alternatives would be preferable to the proposed project with respect to wastewater impacts.

d. Noise

i. Description

The Company asserted that the noise impacts of the proposed project from continuous sources would be less than those of the NGCC and GOCC alternatives, and comparable to those of the RO and PC alternatives (Exh. SCE-23, at 19 through 20). The Company further asserted that the noise impacts of the CGCC alternative would be greater than those of the proposed TEC and the other evaluated alternatives (SCE Supplemental Brief at 134 through 135).

With respect to the proposed project, the Company indicated that continuously operating noise sources, including the induced draft fan exhaust, induced draft fan housing and breeching, cooling tower, main transformer, coal crusher building, turbine/boiler building, ventilation openings and exhaust fan would establish the nighttime levels of noise produced by the proposed TEC (Exh. EFSC-E-57S, at 7-12 through 7-15). The Company indicated that daytime noise levels would be determined by sources confined to daytime operations -- primarily associated with coal and limestone delivery and with ash removal -- and would stem from coal unloading, the rail car moving mechanism, idling locomotives, limestone unloading, and ash pellet loading (id. at 7-15 through 7-17). The Company further indicated that noise mitigation features, including noise controls on major equipment, and layout of facility components to shield major noise sources, have been incorporated into the design of the proposed facility to address all major continuous and daytime sources of noise (id. at 7-19). See Section III.C.2.a.vi., below.

SCE stated that noise from operation of the proposed facility would be in compliance with applicable MDEP standards limiting allowable increases in noise at residences and property lines during facility operations to ten decibels above ambient levels and prohibiting pure tone noise (SCE Brief at 224 through 225).[208] The Company also stated that noise emissions from Conrail locomotives would conform to federal limits of 70 or 73 decibels, depending on date of manufacture, during expected periods of idling in the site vicinity (SCE Brief at 232). However, SCE also submitted noise data for the proposed project indicating that noise impacts at the proposed facility will be significantly higher on the one day each week scheduled for rail delivery of coal and removal of ash (Exh. EFSB-AER-23, Attachment).[209] See Section III.C.2.a.vi., below.

With respect to the technology alternatives, the Company stated that major continuous noise sources would be the same for the proposed TEC and the NGCC, GOCC, CGCC, PC and RO alternatives except that (1) an additional source of noise, the turbine air inlet, would be associated with the NGCC, GOCC, and CGCC alternatives but not with the other aforementioned alternatives, and (2) the proposed TEC and the PC and CGCC alternatives all

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[208] The Siting Board notes that the MDEP noise increase limit is applied based on a measure that reflects the noise level which is exceeded 90 percent of the time.

[209] In addition, Mr. Graban noted his concern that noise impacts from rail delivery to the proposed project both on- and off-site would be unacceptable, particularly in light of the early morning arrival of the coal train (Graban Brief at 1-17 through 1-18).

would require a coal crusher, which would not be required by the NGCC, GOCC and RO alternatives (Exhs. EFSB-AER-21; AG-5-40).

The Company asserted that noise impacts of the proposed TEC, including noise associated with the rail delivery of coal, would be, on balance, comparable to the noise impacts of the NGCC and GOCC alternatives (SCE Supplemental Brief at 135).[210] The Company provided a detailed noise modeling analysis which examined daytime and nighttime noise from the proposed TEC and the alternatives. The analysis provided calculations of daytime and nighttime noise for 10 receptors, including six residential receptors and four TMLP property line receptors located at distances of 800-3,300 feet from the proposed TEC stack, and calculation of daytime noise at one additional residential receptor located along the rail spur that would serve the site i.e., at a total of 11 receptors (Exhs. SCE-23, at 19, Table 9, Table 10; EFSC-E-57S).[211]

With respect to the NGCC and GOCC alternatives, the Company stated that six days/nights per week, (1) nighttime noise produced by the TEC would be less than that of the the gas-fired combined cycle alternatives at seven of ten locations, equal at two locations, and one dBA greater at one location, while (2) daytime noise from the TEC would be less than that of the gas-fired combined cycle alternatives at five locations, equal at five locations, and greater at one location (Exh. SCE-23, at 19, Table 9, Table 10). With respect to the one day per week when the proposed facility would receive rail delivery of coal, the Company indicated that the proposed TEC would have higher daytime noise levels than the gas-fired combined cycle alternatives at all receptors (id.).[212]

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210 The Company asserted that noise impacts generated by the NGCC and GOCC would be similar and stated that its noise analysis, therefore, did not distinguish between these two alternative technologies (SCE Supplemental Brief at 134, n.79).

211 The Company analyzed measurements for nighttime noise at six residential locations, and at seven residential locations for daytime noise (Exh. SCE-23, at 19, Table 9, Table 10).

212 SCE indicated that during the one day per week that coal was delivered, noise levels

(continued…)

The Company stated that noise levels of the PC and RO facilities would be comparable to the proposed TEC because significant noise levels at these facilities would be associated with operation of similar equipment of approximately equal size (id. at 20; Exh. EFSB-AER-21).

With respect to noise levels generated by the CGCC alternative, the Company asserted that the CGCC would have greater noise impacts than the proposed TEC and all other alternatives (SCE Supplemental Brief at 135). The Company stated that the high noise levels at the CGCC alternative would reflect noise production from coal handling and the gasification process in addition to noise impacts equivalent to those of the NGCC and GOCC alternatives (Exh. AG-5-44).[213]

SCE asserted that due to site constraints and the size of the CGCC facility, it might be impossible to place the CGCC facility far enough away from receptors to meet MDEP guidelines for noise impacts (id.). The Company also stated that, on the basis of its estimates of noise propagation from the oxygen plant, just one of several potential sources of noise from the CGCC alternative, noise impacts at Railroad Avenue at night would be 55 dBA, or approximately 25 dBA above ambient background noise and 15 dBA above noise limits established by MDEP (Tr. 30, at 39). The Company indicated that its estimates were based on data supplied by the Attorney General's witness, Dr. Breton, for the LGTI, an existing CGCC facility (id.; Exh. SCE-AG-12).

The Attorney General asserted that the record demonstrated that the site-specific data submitted for the LGTI CGCC facility could not be used as evidence that any other CGCC facility would have unreasonable noise characteristics (Attorney General Supplemental Brief at 160). The Attorney General noted that the LGTI was designed to operate within the confines

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(…continued)

would increase at all receptor locations, with an increase of 1-2 dBA at four residential locations, and 4, 6, and 7 dBA at the three other residential receptor locations, respectively (Exh. SCE-23, at Table 10). At the four property line receptor locations, noise levels would increase by 1, 2, 3, and 5 dBA, respectively (id.).

[213] The Company indicated that flaring operations could be an additional noise source (Exh. EFSB-RR-172; EFSB 90-100R, Exh. HO-RR-111).

of a large industrial area, and that a stricter noise abatement design would have been used for a site such as the proposed TEC site where low noise levels would be required (id. at 161). In addition, Dr. Breton indicated that although portions of the gasification process could not be completety enclosed, noise emissions could be reduced by construction of a brick wall around the gasifier or enclosure of certain significant noise sources (Tr. JH2, at 46 through 47; Tr. JH3, at 62 through 63).

The Attorney General thus argued that the Company's estimate of CGCC noise emissions was inaccurate, that the noise study for the Wabash facility was more reliable than the Company's extrapolation of LGTI data, and that noise mitigation could be incorporated into the design of a CGCC facility (id. at 162 through 164). In sum, the Attorney General asserted that the record did not demonstrate that the proposed TEC would be superior to the CGCC alternative with respect to noise impacts (id.).

ii. Analysis

In comparing the noise impacts of the proposed project and the NGCC alternative the record demonstrates that noise levels would be similar six of seven days per week, but that one day per week, the proposed facility would have increased noise impacts associated with rail delivery of fuel. The Company's analysis of the proposed project demonstrates that rail delivery of fuel is a significant noise source. Thus, with the addition of noise impacts from rail delivery of fuel on a weekly basis, the noise impacts of the proposed facility would be greater than the noise impacts of the NGCC alternative.

Accordingly, based on the foregoing, the Siting Board finds that the NGCC alternative would be preferable to the proposed project with respect to noise impacts.

With respect to the GOCC alternative, the record demonstrates that noise impacts would be similar to the noise impacts of the NGCC alternative. Accordingly, based on the foregoing, the Siting Board finds that the GOCC alternative would be preferable to the proposed project with respect to noise impacts.

In comparing the proposed project to the CGCC alternative, the record demonstrates that insofar as the CGCC alternative is similar in its operation to the NGCC or GOCC, and insofar as it is similar in its coal delivery and handling procedures to the proposed project, its noise impacts are comparable to those of the proposed project. The Company has stated that, compared to the gas combined-cycle alternatives, the proposed project would have slightly lower noise levels on a 6-day-per-week basis, but greater noise impacts associated with railcar movement and on-site handling of coal on the one day per week selected for coal delivery. However, the components of the CFB facility would be completely enclosed while certain portions of the coal gasification process, which is a major source of noise, would be open, and a flare stack would be required only for the CGCC alternative. The Siting Board notes that noise mitigation measures, i.e., silencers, partial enclosures and shielding within the site, can be incorporated into the design of the CGCC alternative to reduce noise of the open components.[214,215] However, because these components must remain open, mitigation measures would not necessarily be as effective as they would be for fully enclosed components. Thus, the record demonstrates that greater mitigation likely would be achieved for the proposed

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214 The Siting Board notes that the flare stack potentially would be an added noise source of significance for the CGCC alternative. The noise emission level of a flaring episode would be comparable to the sound power level of the significant noise sources at both facilities, before mitigation. By virtue of the height of the stack, it is unlikely that the flare stack noise could be shielded by other facility components. In addition, there is no indication in the record that flaring episodes could be limited to specific time periods when the impacts would be reduced.

215 In comparing the noise impacts of the proposed project and the CGCC alternative, the Siting Board does not rely on the Company's noise analysis based on LGTI data or Wabash data provided by the Attorney General. With regard to the Company's noise analysis, the Siting Board notes that (1) possible erroneous assumptions regarding locations of measurements and distances to major sources may have skewed estimates of sound power levels, and (2) the LGTI facility is located within a large chemical complex, and thus, minimization of noise emissions would not be of primary concern. With respect to the noise study of the proposed Wabash facility, the Siting Board notes that it was based on site-specific terrain and configuration of facility components and, therefore, would not be transferable to a CGCC facility located at the proposed site.

project. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the CGCC alternative with respect to noise impacts.

With respect to the RO and PC alternatives, the record demonstrates that the overall noise levels would be comparable to the proposed project. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be comparable to the RO and PC alternatives with respect to noise impacts.

e. Solid Waste

i. Description

The Company indicated that the proposed facility would generate more solid waste than the NGCC, GOCC, CGCC, and RO alternatives but less than the PC alternative (Exh. SCE-23, Table 8). However, the Company asserted that, given the Company's plans for management and disposition of the TEC solid waste, the solid waste impacts of the proposed project would be comparable to those of the natural gas-fired alternatives and preferable to those of the oil and coal-fired alternatives (SCE Supplemental Brief at 131 through 134).

The Company stated that operation of the proposed project would generate approximately 77,000 tpy of solid waste, or ash,[216] but that none of the ash generated by the proposed facility would be deposited in landfills as waste (Exh. SCE-23, at 17 through 18). Instead, the Company indicated that ash would be backhauled to the coal production area for mine reclamation and that some of the ash potentially could be recycled for other environmentally benign purposes (id. at 18; Exh. SCE-1, at 6 through 19). Thus, the Company stated that the solid waste would have no impact on Massachusetts landfills but would have a positive impact in the coal mining region (Exh. SCE-23, at 18). In addition, SCE stated that particulate emissions associated with ash removal would be limited by mitigation measures

216 In estimating solid waste generation, SCE assumed coal sulfur content of 1.6 percent (Exh. AG-42). The Company indicated that solid waste from the proposed facility would increase to (1) 83,500 tpy with use of 1.8 percent sulfur coal, and (2) 88,500 tpy with use of 2.0 percent sulfur coal (Exh. EFSB-AER-25).

including (1) conditioning of ash to be dust-free or use of enclosed rail cars for ash transport, and (2) enclosure of all ash handling operations and venting through fabric filters (id.).

With respect to the NGCC and GOCC alternatives, the Company stated that facility operation would generate approximately 500 tpy of solid waste (id., at Table 8).

With respect to the CGCC alternative, the Company stated that the coal gasification process would generate 40,000 tpy of solid waste, or slag (Exh. AG-5-44).[217] However, SCE asserted that there was no evidence that the slag could be used for mine reclamation or would be a marketable product (SCE Supplemental Brief at 133). As such, the Company asserted that the solid waste impacts of the CGCC alternative would be greater than the solid waste impacts of the proposed project (id.).

With respect to the RO and PC alternatives, SCE stated that the RO alternative would generate 17,520 tpy of solid waste and the PC alternative would generate 83,900 tpy of solid waste (Exh. SCE-23, Table 8). SCE also stated that the RO and PC alternatives would not necessarily incorporate ash conditioning or enclosure of ash handling facilities and, as such, particulate emissions associated with ash removal potentially would be greater for the PC and RO alternatives than for the proposed facility (id. at 18).

ii. The Position of the Attorney General

The Attorney General argued that the natural gas-based alternatives would be superior to the proposed project with respect to solid waste impacts (Attorney General Supplemental Brief at 124 through 125).

The Attorney General argued that the CGCC alternative also would be superior to the proposed project with respect to solid waste impacts (id. at 150 through 153). He argued that the CGCC alternative would generate approximately 48 percent to 55 percent of the total solid

[217] Dr. Breton indicated that the gasification process would cause the coal ash to become molten and then solidify to form slag, a nontoxic and nonleachable glassy substance (Exh. AG-9, at 12). In estimating the amount of slag that would be generated, the Company assumed a ten percent coal ash content (Exh. SCE-5-44).

waste generated by the proposed project,[218] and, in addition, all solid wastes produced by the CGCC alternative would be marketable products (id.).[219] He noted that slag is usable as a construction material (Exh. SCE-AG-67).

iii. Analysis

In comparing the solid waste impacts of the proposed project with the NCGG and GOCC alternatives, the record demonstrates that the proposed project would generate significant amounts of solid waste -- approximately 77,000 tpy -- while the gas-fired alternatives each would generate approximately 500 tpy. The record further demonstrates that, although the Company plans to transport the solid waste to the coal production area for potential reuse as back-fill for coal mines, the Company does not have a specific plan or contract in place.

The Siting Board disagrees with the Company's conclusion that significant differences in the amount of solid waste produced by various technology alternatives are not a measure of solid waste impacts. First, export of significant quantities of solid waste from Massachusetts to another state does not eliminate the impact of solid waste disposal. Second, in the absence of contracts for the transport and use of the solid waste that would be generated by the proposed project, there is no certainty that the waste will be exported and will actually be reused.

Accordingly, based on the foregoing, the Siting Board finds that the NGCC and GOCC alternatives would be preferable to the proposed project with respect to solid waste impacts. In making this finding, the Siting Board recognizes that although a significant amount of solid waste would be generated by the proposed project, the solid waste impacts of the

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218 The Attorney General argued that the heat rate and fuel requirements would be lower than stated by the Company, and, as such, the solid waste generation of the CGCC alternative would be lower than estimated by the Company (see Section II.B.3.e.i, above) (Attorney General Supplemental Brief at 151).

219 Dr. Breton stated that, in addition to slag, sulfur would be produced by the gasification process (Exhs. AG-9, at 6, 12; SCE-AG-41). He stated that the gasification process would remove more than 99 percent of the coal sulfur content and that all sulfur produced at the LGTI facility has been sold (Exhs. AG-9, at 6; SCE-AG-42).

proposed project could reflect a net environmental benefit if the solid waste is reused in the manner suggested by the Company to provide environmental benefits to the coal mining region.

In comparing the solid waste impacts of the proposed TEC and the CGCC alternative, the record demonstrates that the CGCC alternative would generate approximately 53 percent of the solid waste generated by the proposed project. The Siting Board recognizes that the solid waste of both technologies has potential for acceptable reuse that if the waste of both technologies were used in such fashion, impacts of both would be minimized. Nevertheless, the difference in solid waste generation of the two technologies is significant, and as such, for the purposes of this review, impacts of disposal of the solid waste generated by the proposed project would be greater than impacts of the CGCC alternative. Accordingly, based on the foregoing, the Siting Board finds that the CGCC alternative would be preferable to the proposed project with respect to solid waste impacts.

In comparing the RO alternative to the proposed project, the record demonstrates that the RO alternative would generate approximately 23 percent of the solid waste generated by the proposed project. Accordingly, based on the foregoing, the Siting Board finds that the RO alternative would be preferable to the proposed project with respect to solid waste impacts.

In comparing the PC alternative to the proposed project, the record demonstrates that the PC alternative would generate slightly more solid waste -- approximately 9 percent -- than the proposed project. However, the difference in solid waste generation is not a significant difference and the solid waste of the PC alternative also has the potential to be transported to coal mines for reuse as backfill. In addition, the same mitigation measures that will be incorporated into the proposed project to limit particulate emissions associated with ash removal can be incorporated into the PC alternative. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be comparable to the PC alternative with respect to solid waste impacts.

f. Land Use

i. Description

SCE stated that the proposed site consists of approximately 100 acres owned by TMLP ("TMLP property"), of which approximately 25 acres located to the south and west of the existing TMLP facility would be leased by SCE for active facility development for the proposed TEC ("active primary site") (Exh. SCE-3, at III.2-1; Tr. 1 at 136). The active primary site, extending to the southern TMLP property line, consists of land that is presently undeveloped, but significantly disturbed, through prior use as a gravel removal operation (id.).

The Company stated that on-site acreage required by the proposed project and its alternatives, excluding acreage for fuel storage which the Company calculated separately, would range from 8 acres for the NGCC alternative to 30 acres for the CGCC option (Exhs. SCE-23, Table 2; AG-5-40). The Company indicated that fuel storage for the proposed TEC and alternatives, excluding the CGCC alternative, would be .5 acres for the NGCC alternative, 1.2 acres for the RO and GOCC alternatives, and 2 acres for the PC alternative and the proposed TEC (id., Table 1). For the CGCC alternative, the Company stated that 1.9 acres of land would be necessary for 30 days of coal storage and another .7 acres would be required for a 15-day supply of oil as a backup fuel (Exh. AG-5-40).[220] The Company stated that, in the alternative, a firm supply of natural gas could be utilized as a back-up fuel for the CGCC alternative (SCE Supplemental Brief, citing, Tr. JH2, at 62 through 63; Tr. JH3, at 138). With acreage for fuel storage included, the Company estimated on-site acreage of 8.5 acres for the NGCC alternative, 10.2 acres for the GOCC alternative, 19.2 acres for the RO alternative, 22 acres for the proposed TEC, 24 acres for the PC alternative, and 32.6 acres for the CGCC alternative (Exhs. SCE-23, Table 1, Table 2; AG-5-44).

The Company also provided off-site land requirements for the proposed TEC and alternatives (Exh. SCE-23, Table 2). Specifically, the Company stated that only the gas-fired

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[220] The Company indicated that in calculating land area requirements for fuel storage, it included the container area plus containment dikes in the case of oil storage, but included no additional buffer area for any of the alternatives (Exh. EFSB-AER-8).

combined cycle facilities, i.e., the NGCC and the GOCC alternatives, would have off-site land requirements, and that each facility would impact up to 15 acres off-site for gas pipeline construction (id.).[221] With respect to land use impacts for the proposed TEC and alternatives, excluding the CGCC alternative, the Company compared the total on- and off-site land use for each technology and concluded that the total acreage required for each of the four options would be roughly comparable (id. at 9, Table 1, Table 2). The Company also argued that those alternative technologies which would use an existing but unused rail spur at the proposed site would have a positive land use impact insofar as reactivation of the rail spur would enhance its value and economically revitalize the surrounding area (Exh. SCE-23, at 21 through 22; Tr. 26, at 199 through 200).

In comparing the land use requirements of the CGCC alternative to those of the proposed TEC and the other alternative technologies, the Company asserted that, on the basis of its estimates of overall land use requirements for the CGCC alternative, the CGCC alternative could not be accommodated at the active primary site, and that even if it could be accommodated, in laying out the facility there would be insufficient land available to properly buffer the facility from residences or to avoid wetlands (Exh. AG-5-44; Tr. 30, at 70; EFSB-E-57S, at 7-2).

With respect to land requirements for the CGCC alternative, Dr. Breton, the Attorney General's witness, testified that the layout of a Destec process CGCC facility would require no more than 15 or 20 acres (Tr. 33, at 44 through 45; Tr. JH9, at 15 through 25; Exh. EFSB-RR-169, Attachment). Dr. Breton further indicated that all necessary components of the CGCC alternative could easily be configured to fit the available 25-acre site (id.).[222]

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221 The Company estimated that the gas-fired combined cycle alternatives would each require construction of a 2.5-mile pipeline on a 50-foot right-of-way, or approximately 15 acres of land, total (Exh. SCE-23, at 9).

222 Dr. Breton testified that the flexibility of a Destec CGCC facility layout is an advantage over the proposed TEC and stems from the fact that major component blocks such as the gas turbine and heat recovery unit can be separately positioned in keeping with the

(continued…)

Addressing SCE's claim that construction of a pipeline would be necessary to provide natural gas backup for the CGCC alternative, the Attorney General asserted that a gas pipeline built for the CGCC option at the proposed site might avoid any disturbance of virgin land (Attorney General Supplemental Brief at 150, citing, EFSB-AER-14). The Attorney General indicated that several possibilities for routing natural gas for the CGCC alternative without disturbing virgin land had been discussed in this proceeding (id.; Exh. EFSB-AER-13).[223] The Attorney General further indicated that the same possibilities for supplying natural gas to the proposed site for the CGCC alternative without impacts to virgin land could also be utilized for a gas-fired combined cycle (NGCC or GOCC) facility (id.). The Attorney General asserted, therefore, that the CGCC alternative would be superior to the proposed TEC with respect to the environmental impacts of land use (Attorney General Supplemental Brief at 150).

Finally, the Attorney General asserted, therefore, that given that land use impacts of an NGCC or GOCC facility would be 8 or 9 acres respectively, and that off-site land use impacts could be avoided, either of the gas-fired alternatives would be superior to the proposed TEC with respect to environmental impacts of land use (id. at 121 through 124).

ii. Analysis

In comparing the land use impacts of the proposed CFB project and the NGCC alternative, the record demonstrates that the NGCC alternative would require 13.5 acres less for the active facility site but that up to 15 acres may be necessary off-site for pipeline facilities.

(…continued)

contours of the parcel (Tr. 33 at 41, 43 through 44). Dr. Breton stated that the separated blocks would be connected by pipeline to the gasification block (id.).

223 The Attorney General indicated that a pipeline could be built along existing ROW and rail layout from the Algonquin G-1 pipeline, or along existing ROW from the Bay State take station to the TMLP and the proposed site (Exhs. EFSB-AER-12; EFSB-AER-13; EFSB-AER-13S; EFSB-AER-14). The Attorney General indicated that another possibility for supplying natural gas for the CGCC alternative would be via the same Bay State pipeline now serving the TMLP site, with capacity improvements as needed (id.). See Section II.B.3.a, above.

The record further demonstrates that the proposed site has sufficient acreage to accommodate the proposed project and that, in addition, the proposed project has been designed to minimize impacts to on-site and surrounding resources. However, given the proximity of residences to the site, the decreased active site land requirements for a NGCC alternative would allow for substantially greater buffer areas between the aforementioned residences and the active site area. With respect to the 15 acres required for pipeline construction, the Siting Board recognizes that such construction could impact environmentally sensitive resources. However, the extent of impacts that would be necessary is not clear since the record indicates that it may be possible to minimize impacts by limiting construction to existing ROWs and rail layout, or even to deliver natural gas supplies either through pipelines already in place or with enhancement of such pipelines. See Section II.B.3.a, above. Accordingly, based on the foregoing, the Siting Board finds that the NGCC alternative would be preferable to the proposed project with respect to land use impacts.

In comparing the GOCC alternative to the proposed project, the record demonstrates that the GOCC alternative would require 11.8 acres less for the active facility site. The record indicates, however, that 15 acres more may be necessary for off-site pipeline facilities. As with the NGCC alternative, the GOCC alternative is superior to the proposed TEC with respect to on-site land use. With respect to the 15 acres required for pipeline construction, the Siting Board again recognizes the potential impact of such construction on environmentally sensitive resources, but notes the possibility of reducing or altogether avoiding such impacts with careful route selection and/or proper construction techniques. Thus the advantages of the GOCC alternative would be comparable to the advantages of the NGCC alternative. Accordingly, based on the foregoing, the Siting Board finds that the GOCC alternative would be preferable to the proposed project with respect to land use impacts.

With respect to the CGCC alternative, the record provides a range of testimony as to the acreage required for a CGCC facility. Given that the components of the CGCC alternative could be separated, it is reasonable to assume that there would be sufficient flexibility in the layout of the CGCC alternative such that facility components could fit within the confines of the active-site area of the proposed project, thereby minimizing impacts to on-site and abutting resources. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be comparable to the CGCC alternative with respect to land use impacts.

In comparing the RO alternative to the proposed project, the record demonstrates that land use requirements would be similar in that the proposed project would require only 2.8 more acres. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be comparable to the RO alternative with respect to land use impacts.

Finally, in comparing the PC alternative to the proposed project, the record demonstrates that land use requirements would be similar in that the PC alternative would require only 2 more acres. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be comparable to the PC alternative with respect to land use impacts.

g. Findings and Conclusions on Environmental Impacts of the Proposed Project and Alternative Technologies

With respect to fuel transportation impacts, the Siting Board has found that (1) the CGCC alternative would be minimally preferable to the proposed project, (2) the PC alternative would be comparable to the proposed project, and (3) the proposed project would be preferable to the GOCC and RO alternatives. In addition, the Siting Board could make no finding regarding the relative transportation impacts of the proposed project and the NGCC alternative.

With respect to air quality impacts, the Siting Board has found that: (1) the NGCC and GOCC alternatives would be preferable to the proposed project; (2) the proposed project would be preferable to the CGCC alternative; and (3) the proposed project would be comparable to the PC and RO alternatives.

With respect to water supply impacts, the Siting Board has found that (1) the NGCC, GOCC and CGCC would be preferable to the proposed project, and (2) the proposed project would be preferable to the PC and RO alternatives.

With respect to wastewater impacts, the Siting Board has found that (1) the NGCC, GOCC and CGCC alternatives would be preferable to the proposed project, and (2) the proposed project would be preferable to the PC and RO alternatives.

With respect to noise impacts, the Siting Board has found that: (1) the NGCC and GOCC alternatives would be preferable to the proposed project; (2) the proposed project would be comparable to the PC and RO alternatives; and (3) the proposed project would be preferable to the CGCC alternative.

With respect to solid waste impacts, the Siting Board has found that (1) the NGCC, GOCC, CGCC, and RO alternatives would be preferable to the proposed project, and (2) the proposed project would be comparable to the PC alternative.

With respect to land use impacts, the Siting Board has found that (1) the NGCC and GOCC alternative would be preferable to the proposed project, and (2) the proposed project would be comparable to the CGCC, RO and PC alternatives.

In comparing the overall environmental impacts of the proposed project and the NGCC alternative, the Siting Board has found that the NGCC alternative would be preferable to the proposed project with respect to air quality, noise, solid waste, land use, water supply and wastewater impacts. In addition, the Siting Board could make no finding regarding the relative fuel transportation impacts of the proposed project and the NGCC alternative.

The Siting Board notes that, although the NGCC alternative was found to be preferable with respect to solid waste impacts due to the significant amount of solid waste that would be generated by the proposed project, there is potential for the solid waste of the proposed project to have a positive impact in the vicinity of its ultimate disposal. As such, the advantage of the NGCC alternative is limited with respect to solid waste impacts.

In addition, the Siting Board notes that while the total wastewater discharge from the NGCC alternative would be 69 percent of that from the proposed facility, wastewater discharge impacts -- the average concentration of pollutants likely to be added to the Taunton by discharge from both facilities -- would be very small for both technologies and would likely result in comparably minimal impacts. As such, the advantage of the NGCC alternative is limited with respect to wastewater impacts.

However, the Siting Board notes that the NGCC alternative would have significant advantages with respect to air quality. Emissions of criteria pollutants and CO_2 would be far less for the NGCC alternative and, with a potential improvement in heat rate, the emissions advantage of the NGCC alternative would further increase.

The Siting Board also notes that the NGCC alternative would have significant advantages with respect to water supply impacts. While the proposed facility and the NGCC alternative would both operate within the safe yield of the Taunton River and the capacity of the City of Taunton's water supply, total water use and consumptive water use would be markedly greater for the proposed project. Consumptive water use in particular would be 0.80 MGD more for the proposed TEC than for the NGCC alternative. Furthermore, given the potential increased future use of dry low-NOx control technology in NGCC facilities, there is the potential for still greater reduction of water requirements for the NGCC alternative.

With respect to land use, the Siting Board notes that due to the lack of a significant buffer between the proposed project and surrounding residential areas, particularly along Railroad Avenue, the substantially smaller active site area associated with the NGCC alternative presents a significant advantage relative to the proposed project.

Finally, with respect to noise impacts, while the levels of continuous noise of the proposed project and the NGCC alternative are comparable, the noise impacts associated with coal delivery for the proposed project one day per week represents a substantial disadvantage relative to the NGCC alternative as a result of the lack of significant buffer between the proposed project and residential areas.

Accordingly, based on the foregoing, the Siting Board finds that the NGCC alternative would be preferable to the proposed project with respect to environmental impacts.

In comparing the overall environmental impacts of the proposed project and the GOCC alternative, the Siting Board has found that the proposed project would be preferable with respect to fuel transportation impacts, and that the GOCC facility would be preferable with respect to air quality, water supply, wastewater, solid waste, noise and land use impacts.

The Siting Board notes that the advantage of the proposed project with respect to fuel transportation was based on the potential for accidental oil spills in transporting oil to the GOCC alternative. Given that oil would be used for a maximum of two months per year, the advantage of the proposed project with respect to fuel transportation impacts is limited. With respect to solid waste and wastewater impacts, the Siting Board notes that, for the reasons stated above for the NGCC alternative, the advantage of the GOCC alternative would also be limited.

However, with respect to air quality impacts, although the emissions of the GOCC alternative would be slightly higher than those of the NGCC alternative, for the reasons stated above, the Siting Board notes that the advantage of the GOCC alternative also would be significant with respect to air quality. Similarly, with respect to land use impacts, water supply impacts and noise impacts, although such impacts for the GOCC alternative would be slightly greater than for the NGCC alternative, for the reasons stated above, the Siting Board notes that the advantage of the GOCC alternative relative to the proposed project would also be significant.

Accordingly, based on the foregoing, the Siting Board finds that the GOCC alternative would be preferable to the proposed project with respect to environmental impacts.

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

In considering the overall environmental impacts of the CGCC alternative relative to the overall environmental impacts of the proposed project, the Siting Board notes that although fuel transportation impacts would be less for the CGCC alternative than for the proposed project, the advantage of the CGCC would be limited given that both technologies would require rail delivery with the same frequency, and the CGCC alternative would use only slightly fewer railcars per train. With respect to wastewater impacts, the Siting Board notes that, for the reasons stated above for the NGCC alternative, the advantage of the CGCC alternative would be limited. In addition, the Siting Board notes that although less solid waste would be produced by the CGCC alternative, the advantage of the CGCC alternative with respect to solid waste impacts is limited given the potential for the solid waste of the proposed project to have a positive impact in the vicinity of its ultimate disposal.

However, the Siting Board notes that, given the potential for emissions of benzene and H_2S from the CGCC alternative to exceed Massachusetts established standards under worst case conditions, the proposed project would have a significant advantage with respect to air quality. In addition, the record demonstrates that the advantage of the proposed project with respect to noise would be significant given that components of the proposed facility would be enclosed whereas certain portions of the coal gasification process, which is a major source of noise, would be open, and a flare stack would be required only for the CGCC alternative. Finally, with respect to water supply impacts, the Siting Board also notes that, for the reasons stated above for the NGCC alternative, the advantage of the CGCC alternative relative to the proposed project would be significant.

Thus, the CGCC alternative would have significant advantages with respect to water supply, and would have a limited advantage with respect to fuel transportation, wastewater and solid waste impacts. The proposed project would be comparable to the CGCC with respect to land use impacts, but the proposed project likely would have a significant advantage with respect to noise impacts and with respect to air quality impacts. The preferability of the proposed project over the CGCC project with respect to air impacts is particularly marked given the potential for specific emissions from the CGCC alternative to exceed Massachusetts established standards under worst case conditions. Accordingly, on balance, the Siting Board finds that the proposed project would be preferable to the CGCC alternative with respect to environmental impacts.

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

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

In considering the overall environmental impacts of the RO alternative relative to the overall environmental impacts of the proposed project, the Siting Board notes that the proposed CFB project would have a significant advantage with respect to fuel transportation impacts given the potential for accidental oil spills on a year-round basis. The Siting Board also notes that although less solid waste would be produced by the RO alternative, the advantage of the RO alternative with respect to solid waste impacts is limited given the potential for the solid waste of the proposed project to have a positive impact in the vicinity of its ultimate disposal.

Thus, the proposed project would have a significant advantage with respect to fuel transportation impacts, whereas the RO alternative would have a limited advantage with respect to solid waste impacts. Accordingly, on balance, the Siting Board finds that the proposed project would be preferable to the RO alternative with respect to environmental impacts.

4. Cost

In this section, the Siting Board evaluates the proposed project in terms of whether it minimizes cost by determining (1) if the project is superior to a reasonable range of practical alternatives in terms of cost, and (2) if the proposed project offers power at a cost below purchasing utilities' avoided costs.

a. Description

The Company compared the power costs of the proposed project with those of the NGCC, GOCC, CGCC, RO and PC alternatives by using a total revenue requirements methodology (Exhs. SCE-22, at 20; AG-5-44). Essentially, SCE projected the total revenue requirements for each option by year over three time periods -- 20, 30 and 40 years -- with an assumed in-service date of January, 1997 (id.). The Company discounted revenue requirements into NPV terms and then levelized these amounts to derive a cost of power in dollars per megawatt hour ("$/MWh") (id.).[224]

The primary factors considered by the Company in its cost analysis were: (1) capital costs; (2) O&M costs; (3) fuel costs; (4) interest rates;[225] (5) availability factor;[226] and (6) heat rate (Exhs. SCE-22 at 19 through 20 and att. RLC-33). In calculating capital, O&M, and fuel costs, the Company established a base cost and then escalated base costs in accordance with respective escalation rates provided in the GTF (id. at 21; Tr. 27, at 57, 64).[227] The Company also provided higher and lower scenarios for (1) fuel cost, assuming annual escalation factors for each fuel at ten percent higher and lower than the GTF in every year beyond 1992, and (2) interest rate, assuming a two percent increase and decrease in interest rates (Exhs. SCE-22, at 24 through 25; AG-5-44). The Company indicated that its analysis demonstrated that the proposed project would be preferable to the CGCC, NGCC, GOCC, RO and PC technology alternatives with respect to cost under all scenarios analyzed (id.).

For the proposed project, SCE calculated a levelized cost based on project-specific estimates of base 1997 capital and annual cost, and escalation of annual costs by the 1992 GTF

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[224] In projecting total revenue requirements for each alternative, the Company utilized consistent assumptions with respect to cost of debt, cost of capital, tax rate, and depreciation (Exh. SCE-22, at 20 and att. RLC-32).

[225] For the proposed project and all technology alternatives, SCE assumed a debt term of 20 years and an interest rate of 9.5 percent (Exh. SCE-22, att. RLC-32).

[226] The Company explained that availability factor represents the percentage of time a generating unit would be available when required for power generation (Tr. 29, at 10 through 11).

[227] The Company noted that the 1992 GTF escalation rates extend to the year 2010 and that it assumed 1992 GTF-specified escalation rates for the period 2006 to 2010 for its cost analysis for years beyond the year 2010 (Exh. AG-34).

escalation factors (Tr. 27, at 37). See Table 9. The Company stated that fuel costs were based on an approximate market price for 1997 and escalated by the 1992 GTF escalation factors (Tr. 28, at 151 through 152). The Company explained that its coal contract would be market-based with an escalator for inflation and would establish an initial price with the first delivery of coal (see Section II.C., below) (id. at 153; Tr. 27, at 60 through 61).[228]

In calculating the levelized cost for the NGCC, GOCC, CGCC, RO and PC technology alternatives, the Company utilized 1992 GTF data to determine availability factors, heat rate, base 1997 capital costs, and base 1997 O&M costs (Exhs. SCE-22 at 20; AG-5-44; Tr. 27, at 64).[229] In order to provide cost estimates consistent with the cost estimate of the proposed project, the Company adjusted certain 1992 GTF-specified data (Exhs. SCE-22, at 21 through 23; AG-5-44). Specifically, for all technology alternatives, the Company incorporated modifications to the 1992 GTF as follows: (1) heat rate adjustments to reflect the steam export of the proposed project; (2) capital cost adjustments to reflect the TEC's actual transmission line construction costs; and (3) heat rate, capital cost and O&M cost adjustments to reflect installation and operation of control technology to meet current BACT standards for NOx control (id.; Tr. 27, at 86). The Company asserted that, even with the aforementioned adjustments, use of industry data such as the 1992 GTF likely would understate costs of the alternatives because it fails to reflect certain project-specific and site-specific costs that were incorporated into the cost estimate for the proposed project including (1) project development costs, and (2) environmental mitigation costs in such areas as noise, wetlands protection, air quality and visual impacts (SCE Supplemental Brief at 72).

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228 Mr. La Capra explained that the coal contract would contain market price adjustments and that the Company expects that the actual coal price will be less than current estimates (Tr. 27, at 61). He noted that the contract would limit price increases to the Consumer Price Index (id. at 63 through 64).

229 The Company indicated that the 1992 GTF is the best single source for a comparison of technology alternatives because it is recent and New England-specific (Exh. SCE-22, at 21).

With respect to technology alternative fuel costs, SCE calculated a base 1992 price for each fuel based on the average year-to-date 1992 delivered prices to New England utilities and then applied the fuel-specific 1992 GTF escalation rates to the base 1992 prices ("SCE fuel forecast") (Exh. SCE-22, at 21 and att. RLC-34; Tr. 27, at 113 through 114; Tr. 28, at 140 through 142).[230]

For the NGCC alternative, SCE provided levelized costs for base, high and low scenarios based on the SCE fuel forecast[231] and, in response to a request of the Siting Board Staff, provided an additional set of levelized costs based on a fuel forecast reflecting spot gas prices reported in the November 9, 1992 "Natural Gas Week" ("NGW fuel forecast") (Exhs. SCE-22, at 21; EFSB-AER-32).[232] See Table 9.

For the GOCC alternative, the Company similarly provided sets of levelized costs, including base, high and low scenarios, based on the SCE fuel forecast[233] and the NGW fuel forecast (Exhs. SCE-22, at 21; EFSB-AER-32). The Company noted that the levelized cost of

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230 SCE noted that actual year-to-date 1992 fuel prices were lower than 1992 GTF-specified 1992 prices for distillate oil, residual oil and 1.8 percent sulfur coal but greater than 1992 GTF-specified 1992 prices for interruptible and firm gas (Exh. SEC-22, att. RLC-34).

231 Mr. La Capra indicated that the 1992 firm gas price was based on 110 percent of the average 1992 spot gas prices through October 1992 and transportation prices estimated by Algonquin (Exh. SCE-22, att. RLC-34). He noted that such price was less than the actual New England year-to-date firm gas price (id.).

232 For the NGW fuel forecast, SCE also provided levelized costs based on a higher and a lower fuel price scenario which assumed ten percent higher/lower annual escalation factors (Exh. EFSB-AER-33).

233 SCE indicated that the 1992 interruptible gas price was based on the average spot prices through October 1992 and transportation prices estimated by Algonquin (Exh. SEC-22, att. RLC-34). SCE also indicated that the 1992 price for distillate oil for the GOCC alternative was based on the year-to-date price for standard 0.2 percent to 0.3 percent sulfur distillate oil, adjusted upward by two cents per gallon to reflect the cost of utilizing 0.05 percent sulfur distillate oil, consistent with the environmental analysis (Exh. SCE-22, at 23).

the GOCC alternative would be less than the levelized cost of the proposed project under one scenario -- the 20-year, low fuel cost scenario based on the NGW fuel forecast (Exh. EFSB-AER-32). See Table 9.

In response to an additional request of the Siting Board Staff, the Company also provided levelized costs of the GOCC alternative based on a higher availability factor of 92 percent[234] and the SCE fuel forecast (Exh. EFSB-RR-154). The Company indicated that even with an increased availability factor, the levelized costs of the GOCC alternative would be greater than the levelized costs of the proposed facility under all of the scenarios based on the SCE fuel forecast (id.). See Table 9. However, the Company maintained that a 92 percent availability would be inappropriate for the GOCC alternative, and that, given the assumed fuel supply, the actual availability of the GOCC alternative likely would be lower than even the GTF-specified availability of 86.8 (id.). The Company explained that the natural gas supply -- 10 months of interruptible supply over a 20-year period -- was not a realistic supply option because interruptible supplies historically have been available in New England for only eight to nine months (id.). SCE further stated that an increase in oil firing also would not be a realistic assumption because (1) costs would increase, and (2) more than two months of oil firing would not be allowed under environmental permits (id.). SCE stated that, therefore, the GOCC alternative would be effectively unavailable for up to two months annually (id.). SCE added that the cost of the GOCC would increase considerably with a firm ten-month gas supply (id.).

With respect to the CGCC alternative, the Company provided levelized costs based on the SCE fuel forecast for 1.8 percent sulfur coal (Exh. AG-5-44). The Company asserted that the GTF-specified availability factor of 85 percent utilized in the cost analysis was optimistic, noting that the availability factor of the LGTI facility has averaged approximately 60 percent over five years of operation (see Section II.B.6, below) (SCE Supplemental Brief at 83, 85,

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234 The Company noted that the 92 percent availability factor was based on the anticipated availability factor for a proposed natural gas-fired combined cycle facility (Tr. 29, at 17). The Company further noted that said availability factor was not guaranteed for the proposed facility, but was based on the actual performance of another existing facility (id.).

citing, Exh. JH-RR-2).[235] The Company indicated that a decrease in availability from 85 percent to 60 percent would increase costs significantly (Exhs. SCE-AG-25, at 6-1 through 6-3).

In addition, the Company asserted that there was no basis for the lower heat rate and lower cost estimates for the CGCC alternative provided by Dr. Breton (see Section II.B.3.b, above) (SCE Supplemental Brief at 86 through 90). SCE further asserted that the capital cost estimate computed by Dr. Breton was based on incorrect industry-wide data and unsubstantiated costs for NOx control technologies while Dr. Breton's estimate of O&M expenses omitted relevant cost items (id. at 86 through 88, citing, Exhs. EFSB-RR-170; EFSB-RR-171).[236]

For the PC and RO alternatives, the Company provided levelized costs based on the SCE fuel forecast (Exh. SCE-22 at 21 through 24). See Table 9.

Finally, the Company provided analyses of the project costs of its proposed project relative to the avoided costs of four Massachusetts utilities (Exh. SCE-2, app. C). These analyses indicated that SCE would be able to offer its power at or below all of the utilities' avoided costs (id.).

b. Position of the Attorney General

The Attorney General argued that application of the Department's externality values to the pollutant values for the proposed project and the NGCC alternative demonstrate that the proposed project would involve substantially more costs than the NGCC alternative (Attorney

235 SCE noted that Dr. Breton acknowledged that "when the 85 percent is reached by an operating plant, you can say that gasification has arrived in terms of a strong competitor with any other coal based technology" (SCE Supplemental Brief at 84, citing, Tr. JH2, at 146 through 147).

236 SCE noted that although Dr. Breton's capital cost estimate was comparable to the capital cost estimate for the proposed Wabash facility, said facility will utilize a significant amount of existing facilities and, as such, the capital cost of the proposed Wabash facility represents only a portion of the capital cost of an entirely new CGCC facility (id., citing, Tr. JH3 at 95 through 96; Tr. JH9, at 40 through 41).

General Supplemental Brief at 165 through 166 and Figure 1).[237] In addition, the Attorney General argued the levelized costs of the NGCC alternative were inflated (id. at 166 through 168).

Specifically, the Attorney General argued that the Company assumed an excessive heat rate of 8,553 Btu/KWh for the NGCC alternative and that a more realistic heat rate would be 7,818 Btu/KWh (see Section II.B.3.b, above) (id. at 167, citing, Exhs. EFSB-AER-22; SCE-22, att. RLC-36). The Attorney General indicated that such a reduction in heat rate of 8.6 percent would reduce fuel requirements and variable costs by a like percentage (id.). The Attorney General indicated that the 20-year levelized cost of $74.31 for the Altresco Lynn facility, a proposed 170 MW gas-fired combined cycle unit, provides further evidence that the Company's levelized cost of $98 for the NGCC alternative is overstated (id.).[238]

With respect to the CGCC alternative, the Attorney General argued that Dr. Breton utilized an appropriate method to derive his capital cost estimate for the CGCC alternative -- which estimate is only slightly higher than the Company's capital cost estimate for the proposed facility (id. at 170). The Attorney General added that the differences in capital costs between the two technologies would not be significant over the life of the facilities (id.). In addition, the Attorney General provided that the heat rate of a 150 MW CGCC facility would be lower than the heat rate assumed by the Company, decreasing annual fuel requirements and associated costs (Exh. AG-RR-50; Tr. 33 at 13; Tr. JH3, at 43).

The Attorney General also argued that the levelized cost of a Destec coal-gasification plant would be reduced to the levelized cost of a CFB plant by the time that there is a need for new power in the region given that Destec's technology is improving and identified problems are being rectified (Attorney General Supplemental Brief at 171). Finally, in explaining the

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237 The Attorney General's arguments regarding the incorporation of externality values into the cost analysis were addressed in Section II.B.1.b., above.

238 The Attorney General also argued that the Company's natural gas price projection is inconsistent with the historical 30 percent decrease in natural gas prices from January 1982 to June 1992 (Attorney General Supplemental Brief at 167, citing, Exh. EFSB-AER-35, revised RLC-48).

historical availability of the LGTI facility in the 60 percent range,[239] Dr. Breton stated that the facility is a demonstration plant, that modifications and improvements to plant systems have continued since initial operation in 1987, and that significant improvements have been made to the processes that have contributed most to plant outages (Exhs. AG-9, at 7; JH-RR-2; Tr. JH at 83 through 87). The Attorney General noted that the availability of the gasification process would reach 85 percent in the mid- to late-1990's and that the most significant economic constraint to the development of CGCC facilities is the low price and abundant supply of natural gas, which is the direct competitor of syngas, the fuel produced from coal and used in CGCC facilities (Tr. JH2, at 140 through 141; Tr. JH3, at 117 through 118).

c. Analysis

As a preliminary matter, in comparing the levelized cost of the proposed project to the technology alternatives, the Siting Board recognizes that the capital cost estimates for the technology alternatives likely would be understated relative to the capital cost estimates for the proposed project. The capital cost estimates for the proposed project include site-specific and project-specific costs, such as the cost of noise mitigation and wetlands protection that are not included in the capital cost estimates for the technology alternatives.

With respect to the proposed project, the record demonstrates that: (1) the 20-year levelized cost would range from 79.02 $/MWh to 85.33 $/MWh; (2) the 30-year levelized cost would range from 81.45 $/MWh to 87.23 $/MWh; and (3) the 40-year levelized cost would range from 83.59 $/MWh to 89.57 $/MWh, under the various cost assumptions. In comparing the cost of the proposed project to the NGCC alternative, the record demonstrates that, assuming the SCE fuel forecast, and the heat rate for the NGCC alternative provided by the Company: (1) the 20-year levelized cost would range from 91.44 $/MWh to 105.10 $/MWh; (2) the 30-year levelized cost would range from 99.50 $/MWh to 114.80 $/MWh; and (3) the 40-year levelized cost would range from 106.62 $/MWh to 123.29 $/MWh, all greater than the

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239 Dr. Breton indicated that the anticipated availability of the Wabash facility was proprietary and confidential (Tr. JH2, at 145 through 146).

corresponding levelized costs of the proposed facility. The record further demonstrates that the levelized cost of the NGCC alternative would increase for all time periods under the NGW forecast. See Table 9.

The Attorney General argued that the levelized costs of the NGCC alternative should be reduced by 8.6 percent to correspond to an 8.6 percent reduction in heat rate, based on the heat rate of a currently proposed NGCC facility. In the EEC (remand) Decision, the Siting Board acknowledged that a 16.6 percent reduction in the heat rate of a NGCC facility would provide a 6.7 percent reduction in levelized costs. 1 DOMSB at 375. Thus, in that review, the reduction in levelized costs was 40.4 percent of the reduction in heat rate.

We recognize that a reduction in heat rate would result in a reduction in levelized costs. As noted in the EEC (remand) Decision, however, the percentage reduction in cost does not correspond directly to the percentage reduction in heat rate. For purposes of review in this case, in order to adjust SCE's cost estimate to reflect a lower heat rate for the NGCC alternative, we will apply the same ratio of cost to heat rate reduction as applied in the EEC (remand) Decision. This ratio corresponds to a 3.5 percent reduction in the levelized costs of the NGCC alternative. However, even with said reduction, the levelized costs for the NGCC alternative would remain greater than the levelized costs of the proposed facility under each of the time periods and fuel forecasts analyzed.[240]

In the EEC (remand) Decision, 1 DOMSB at 375-376, the Siting Board also considered a NGCC alternative with a firm gas supply for 356 days. The Siting Board recognized that recently constructed natural-gas fired facilities typically do not have a firm gas supply for 365 days. Instead, a more likely fuel supply would be a firm gas supply for ten months with an interruptible gas supply and oil back-up for a short period of time. See, also, West Lynn Decision, 22 DOMSC at 73; MASSPOWER Decision, 20 DOMSC at 361-367;

240 We recognize that in this case the Company assumed a heat rate for the NGCC alternative that is consistent with recently proposed and approved NGCC facilities. See, Altresco Lynn Decision, 2 DOMSB at 128. Nevertheless, the lower heat rate is consistent with the lower range of heat rate of recently proposed projects. See, Cabot Power Decision, 2 DOMSB at 350.

NEA Decision, 17 DOMSC at 379-380, 398. The Siting Board recognized that such a fuel supply would likely reduce levelized costs but that a firm natural gas supply for 365 days would not be an unreasonable assumption, and projects with such arrangements have been proposed and approved. Id. See also, Cabot Power Decision, 2 DOMSB at 366; Enron Decision, 23 DOMSC at 7. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the NGCC alternative with respect to cost.[241]

In comparing the cost of the proposed project with the GOCC alternative, the record demonstrates that, assuming the heat rate and availability for the GOCC alternative provided by the Company and the SCE fuel forecast: (1) 20-year levelized cost would range from 83.90 $/MWh to 96.88 $/MWh; (2) the 30-year levelized cost would range from 94.49 $/MWh to 108.69 $/MWh; and (3) the 40-year levelized cost would range from 103.74 $/MWh to 119.78 $/MWh, all greater than the corresponding levelized costs of the proposed facility. Further, assuming the same reduction in heat rate and associated decrease in levelized costs assumed for the NGCC alternative, the levelized cost of the GOCC alternative would remain greater than the levelized cost of the proposed facility under the SCE fuel forecast. In addition, assuming an increase in availability factor, the levelized costs of the GOCC alternative under the SCE fuel forecast would remain greater than the corresponding costs of the proposed facility, even when the increased availability factor is combined with a decrease in heat rate.

However, the levelized costs of the GOCC alternative would decrease under the NGW fuel forecast for all scenarios. Under one scenario -- 20-year/low fuel price -- the levelized cost of the GOCC alternative (79.11 $/MWh) would be less than the levelized cost of the proposed facility (79.45 $/MWh). In addition, under the NGW fuel forecast and the Attorney General's lower heat rate assumption, the levelized cost of the GOCC alternative for the base

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[241] The Siting Board recognizes that levelized costs for specific or generic facilities can be compared only where all cost assumptions (i.e., factors included in capital and O&M base costs and escalators, interest rate, rate of return) are identical. Thus, the Siting Board disagrees with the Attorney General that the levelized cost of the proposed Altresco-Lynn facility demonstrates that the Company's estimation of levelized cost for the NGCC alternative is overstated.

fuel price and low fuel price scenarios over 20 years would be less than the corresponding costs of the proposed facility, while the levelized costs of the GOCC alternative for all scenarios over 30 or 40 years would remain greater than corresponding costs of the proposed facility.

Therefore, considering costs on a 20-year basis, the GOCC facility would be less costly than the proposed project under certain fuel price/heat rate scenarios. However, the Siting Board recognizes that the costs of a generating facility are likely to be spread over a 30-year or more period and that the capital costs of the proposed facility are higher than the capital costs of the GOCC alternative. Thus, the use of a 20-year period for calculating levelized cost would increase the levelized cost of the proposed project relative to the GOCC alternative.

Further, in the EEC (remand) Decision, 1 DOMSB at 376, the Siting Board reviewed a GOCC alternative with a similar interruptible fuel supply. The Siting Board recognized that the assumed natural gas supply of the GOCC alternative -- 10 months of interruptible gas -- would not be a realistic supply option. A facility that has an assured fuel supply for only two months would not be financiable. The Siting Board noted that, as with the NGCC alternative, a more realistic fuel supply for a GOCC facility would be firm gas for ten months with an interruptible gas supply and oil back-up for a maximum of 35 days. See also, West Lynn Decision, 22 DOMSC at 73; MASSPOWER Decision, 20 DOMSC at 361-367; NEA Decision, 16 DOMSC at 379-380, 398.

As such, the Siting Board considers the cost of the GOCC facility to reflect the lower end of a likely range of costs for a GOCC facility and the cost of a viable GOCC facility with a realistic fuel supply would fall most likely between SCE's estimated costs for the GOCC alternative and NGCC alternatives. Further, although the Company's GOCC alternative shows levelized cost advantages under certain favorable assumptions for that alternative, such advantages are relatively slight. Thus, it is likely that a realistic fuel supply would result in a cost disadvantage for the GOCC alternative, even under favorable assumptions. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the GOCC alternative with respect to cost.

In comparing the cost of the proposed project with the CGCC alternative, the record demonstrates that, based on the heat rate provided by the Company: (1) 20-year levelized cost would range from 93.03 $/MWh to 102.16 $/MWh; (2) the 30-year levelized cost would range from 96.80 $/MWh to 105.04 $/MWh; and (3) the 40-year levelized cost would range from 100.78 $/MWh to 108.73 $/MWh, all greater than the corresponding levelized costs of the proposed facility.

The Attorney General raised concerns regarding the Company's calculation of heat rate for the CGCC alternative. The Attorney General's witness indicated that the heat rate of a CGCC facility, consistent with the proposed project, would be less than the heat rate estimated by the Company, leading to a reduction in costs. However, unlike the lower heat rate provided for the NGCC alternative which was based on a proposed facility, the heat rate estimates provided by the Attorney General for the CGCC alternative were based on theoretical facilities. There are no existing CGCC facilities with the characteristics of the theoretical facilities used as a basis for the Attorney General's heat rate estimates.

Finally, the record demonstrates that the availability factor assumed by the Company for the CGCC alternative, 85.5 percent, is representative of an availability factor for a mature technology rather than a technology that has not yet reached a mature status. Although an availability factor in the range of 85 percent is anticipated for the technology, there is no evidence in the record that operating facilities have achieved 85 percent availability or that currently proposed facilities anticipate this availability factor. Further, there is no assurance such an availability factor would be reached by operating facilities by the time the proposed project is expected to commence operation in the 1997 to 2000 time frame. With a decrease in the assumed availability factor of 85.5 percent, levelized costs of the CGCC alternative would increase. Accordingly, the Siting Board finds that the proposed project would be preferable to the CGCC alternative with respect to cost.

In comparing the cost of the proposed project to the PC alternative, the record demonstrates that: (1) 20-year levelized cost would range from 123.07 $/MWh to 133.57 $/MWh; (2) the 30-year levelized cost would range from 134.64 $/MWh to 144.13 $/MWh;

and (3) the 40-year levelized cost would range from 146.91 $/MWh to 156.05 $/MWh, all greater than the corresponding levelized costs of the proposed facility. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the PC alternative with respect to cost.

In comparing the cost of the proposed project to the RO alternative, the record demonstrates that: (1) 20-year levelized cost would range from 102.71 $/MWh to 113.80 $/MWh; (2) the 30-year levelized cost would range from 115.37 $/MWh to 128.54 $/MWh; and (3) the 40-year levelized cost would range from 127.52 $/MWh to 142.41 $/MWh, all greater than the corresponding levelized costs of the proposed facility. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the RO alternative with respect to cost.

In addition, the record indicates that SCE could provide power at a cost below the avoided costs of several Massachusetts utilities. Accordingly, the Siting Board finds that the proposed project is likely to offer power at a cost below purchasing utilities' avoided costs.

5. Reliability

In this section the Siting Board compares the proposed project to the technology alternatives with respect to unit-specific reliability. The Siting Board notes that unit-specific reliability relates to the predictability of unit operation. As such, the Siting Board considers such factors as the anticipated availability and the reliability of the fuel supply in comparing the reliability of the proposed project with the reliability of the technology alternatives. Altresco Lynn Decision, 2 DOMSB at 131; EEC (remand) Decision, 1 DOMSB at 379.

The Company asserted that the proposed project would be comparable to the PC alternative and preferable to all other technology alternatives with respect to reliability (SCE Supplemental Brief at 154 through 157). The Company stated that the availability of the proposed project would be 85 percent (Exh. SCE-22, att. RLC-33). However, the Company stated that the overall reliability advantages of coal as a fuel source stem from (1) abundant supplies with at least 200 years of domestic coal supply available at current production levels, and (2) stabile prices (id. at 26). Specifically, the Company stated that the proposed project has a possible long-term coal contract with a strong domestic producer and firm coal transportation arrangements via an existing transportation infrastructure (id. at 27; Exh. SCE-23 at 3). See Sections II.C., and III.C.2.a.vii., below.

With respect to the NGCC alternative, SCE stated that the availability factor, 86.8 percent, would be comparable to the availability factor of the TEC (Exh. SCE-22, at 25 and att. RLC-33). In addition, the Company stated that once gas pipeline facilities were in place, the reliability of fuel transportation would be comparable for the TEC and the NGCC alternative (id. at 28).[242] The Company also stated that, although not certain, it was reasonable to assume that the Company could obtain a firm natural gas supply at the proposed site (Tr. 27, at 105).[243] However, the Company stated that coal would generally be a more reliable fuel supply than natural gas, and would reduce Massachusetts' exposure to volatile changes in energy costs because (1) the reserve to production ratio for domestic natural gas represents less than ten years of supply at current levels, and (2) natural gas prices have historically been volatile (id. at 26 through 27 and att. RLC-48).[244]

In comparing the reliability of the proposed project to the NGCC alternative, the Siting Board notes that the slight benefit in availability of the NGCC alternative relative to the

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242 Mr. La Capra stated that although gas pipeline capacity to the region would have to be expanded significantly to support the expansion of firm gas transportation to power generation facilities, it likely would be possible to transport firm gas to the TEC site via an Algonquin pipeline and other upstream pipelines (Exh. SCE-22, at 28). However, he stated that it would be unlikely that sufficient additional pipeline capacity could be constructed to support new generation requirements in addition to expansion in other uses (id.).

243 Mr. La Capra stated that Distrigas of Massachusetts has indicated that it would discuss supply with potential buyers and may offer a supply at competitive gas prices (Tr. 27, at 111 through 112).

244 SCE stated that the high escalation rates projected for gas in the 1992 GTF, relative to the escalation rates projected for coal, reflect the relative scarcity of natural gas supplies and the expectation that natural gas demand will increase due to regulations restricting air emissions and new markets and technologies (Exh. SCE-22, at 26).

proposed project of 1.8 percent does not represent a significant difference for purposes of this review. With respect to fuel supply and transportation, the record demonstrates that a firm supply and firm transportation of natural gas potentially could be available to a generating facility at the proposed site. In addition, the record provides no evidence that natural gas supplies are constrained such that supplies would not be available for the life of a facility. Further, the Siting Board has noted that while a 365-day firm gas supply may not be typical, it is a realistic approach which is likely to be both financiable and viable. See Section II.B.4.c, above. Accordingly, based on the foregoing, the Siting Board finds that the NGCC alternative and the proposed project would be comparable with respect to reliability.

With respect to the GOCC alternative, the Company assumed the 1992 GTF-specified availability factor of 86.8 percent (Exh. SCE-22 at att. RLC-33). However, the Company asserted that the actual availability factor would be considerably less given that interruptible gas likely would not be available for ten months on a continuous basis and environmental laws would limit use of oil as a back-up fuel (SCE Supplemental Brief at 154). The Company added that the firm fuel supply and transportation arrangements of the proposed facility would be preferable to reliance on interruptible gas which would be subject to regular curtailment, primarily during periods of cold weather (Exh. SCE-22, at 25 through 27).

The Siting Board notes that the GOCC alternative does not have a realistic fuel supply and likely would not be financiable or permitable based on the assumed fuel supply (see Section II.B.4.c, above). Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the GOCC alternative with respect to reliability.

With respect to the CGCC alternative, the Company assumed the 1992 GTF-specified availability factor of 85.5 percent but, as noted above, asserted that such availability factor would be optimistic (id., att. RLC-33; SCE Supplemental Brief at 82 through 85). In addition, SCE indicated that the CGCC alternative would be comparable to the proposed project with respect to fuel supply and transportation ((Exh. SCE-22, at 25 through 26).

In Section II.B.6.c, above, the Siting Board reviewed the Company's and parties' arguments regarding the availability factor of the CGCC alternative. The Siting Board acknowledged that, although an availability factor in the range of 85 percent is expected over the long term for the technology, there is no evidence in the record that operating facilities have achieved 85 percent availability or that currently proposed facilities anticipate this availability factor. The Siting Board also acknowledged that there is no assurance that such an availability factor would be reached by operating facilities by the time the TEC project is expected to commence operation in the 1997 to 2000 time frame.

Therefore, the record demonstrates that the CGCC technology has not achieved an availability factor comparable to that of the proposed project. A lower, and currently more realistic availability factor would have a negative impact on the likely reliability and commercial viability of a CGCC alternative intended for the same time frame as the proposed project. Thus, based on the record in this proceeding, the CGCC alternative likely would not be a viable or reliable source of energy supply within the time frame in which the proposed facility would come on-line. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the CGCC alternative with respect to reliability.

SCE indicated that the availability of the PC alternative, 81.4 percent, and the reliability of its fuel supply and transportation, would be comparable to the availability and reliability of fuel supply and transportation of the proposed project (id. at 25 through 26 and att. RLC-33).

In comparing the reliability of the proposed project to the PC alternative, the Siting Board notes that the slight benefit in availability of 3.6 percent for the proposed project relative to the PC alternative does not represent a significant difference for purposes of this review. In addition, the record indicates the reliability of fuel supply for the proposed project and the PC alternative would be comparable. Accordingly, based on the foregoing, the Siting Board finds that the proposed project and the PC alternative would be comparable with respect to reliability.

SCE indicated that the availability of the RO alternative, 84.7 percent, would be comparable to the availability of the proposed project but that the proposed project would be preferable with respect to fuel supply and transportation reliability because oil is largely imported while coal is domestic (id. at 25 through 26 and att. RLC-33). SCE stated that reliability problems associated with dependence on imported oil have been demonstrated in the form of major supply disruptions and price spikes (id. at 26). In comparing the reliability to the proposed project to the RO alternative, the Siting Board notes that the availabilities would be comparable. Further, with respect to the reliability of fuel supply and transportation, the record provides no evidence that oil supplies would not be available at the proposed site. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be comparable to the RO alternative with respect to reliability.

6. Comparison of the Proposed Project and Technology Alternatives

a. Comparison

In City of New Bedford, the SJC stated that "the statute mandates that the [Siting C]ouncil balance environmental harm that would be caused by a new power plant against the other statutory objectives -- providing a necessary energy supply at the lowest possible cost." 413 Mass. at 485. In addition, the SJC stated "[t]he statutory mandate, however, requires that the energy the facility will supply is necessary for the Commonwealth; that the supply of the energy involves a minimum impact on the environment; and that such energy is supplied at the lowest possible cost. Thus, the statutory balance involves weighing minimum environmental impact and cost." Id., 413 Mass. at 486. In addition, the SJC stated that the Siting Council would need to explicitly state that it was approving a project with greater environmental impacts than alternatives on the basis of a determination that other factors outweighed those environmental impacts. Id. at 490. See also, Attorney General Brief at 97.

In Section II.B.1.c, above, the Siting Board found that, 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 would require the applicant to establish 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.

In Sections II.B.3, II.B.4, II.B.5, above, the Siting Board has analyzed the record, as directed by the SJC, by comparing the proposed project against generating technology alternatives that have been determined to be capable of meeting the identified need, on the basis of their specific impacts on the environment, costs and reliability.

In comparing the environmental impacts of the proposed project to the environmental impacts of the technology alternatives, the Siting Board has found that (1) the NGCC and GOCC alternatives would be preferable to the proposed project with respect to environmental impacts and (2) the proposed project would be preferable to the CGCC, PC and RO alternatives with respect to environmental impacts.

In comparing the costs of the proposed project to the costs of the technology alternatives, the Siting Board has found that the proposed project would be preferable to the NGCC, GOCC, CGCC, PC, and RO alternatives with respect to cost.

In comparing the reliability of the proposed project to the reliability of the technology alternatives, the Siting Board has found that (1) the proposed project would be preferable to the GOCC and CGCC alternatives with respect to reliability, and (2) the proposed project would be comparable with respect to the NGCC, PC and RO alternatives with respect to reliability.

Thus, in comparing the environmental impacts, cost and reliability of the proposed project to the environmental impacts, cost and reliability of the technology alternatives, the Siting Board notes that: (1) the NGCC alternative would be preferable to the proposed project with respect to environmental impacts, the proposed project would be preferable to the NGCC alternative with respect to cost and the proposed project would be comparable to the NGCC alternative with respect to reliability; (2) the GOCC alternative would be preferable to the proposed project with respect to environmental impacts while the proposed project would be preferable to the GOCC alternative with respect to cost and reliability; (3) the proposed project would be preferable to the CGCC alternative with respect to environmental impacts, cost and reliability; (4) the proposed project would be preferable to the PC alternative with respect to both environmental impacts and cost and the proposed project would be comparable to the PC alternative with respect to reliability; and (5) the proposed project would be preferable to the

RO alternative with respect to both environmental impacts and cost and the proposed project would be comparable to the RO alternative with respect to reliability.

In balancing the environmental impacts, cost and reliability of the proposed project and the technology alternatives, the Siting Board first considers the proposed project in relation to the CGCC, PC, RO and GOCC alternatives. The Siting Board then considers the proposed project in relation to the NGCC alternative.

As noted above, the proposed project is preferable to the CGCC alternative with respect to environmental impacts, cost and reliability. Accordingly, based on the foregoing, the Siting Board finds that the proposed project is superior to the CGCC alternative with respect to providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

With regard to the PC alternative, as noted above, the proposed project is preferable to the PC alternative with respect to environmental impacts and cost. Further, the proposed project is comparable to the PC alternative with respect to reliability. Accordingly, based on the foregoing, the Siting Board finds that the proposed project is superior to the PC alternative with respect to providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

With regard to the RO alternative, as noted above, the proposed project is preferable to the RO alternative with respect to environmental impacts and cost. Further, the proposed project is comparable to the RO alternative with respect to reliability. Accordingly, based on the foregoing, the Siting Board finds that the proposed project is superior to the RO alternative with respect to providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

As noted above, the Siting Board has found that the GOCC alternative would be preferable with respect to environmental impacts. However, the proposed project would be preferable with respect to cost. Further, the Siting Board has found that the proposed project would be preferable with respect to reliability as the GOCC alternative does not have a realistic fuel supply and likely would not be financeable or permittable based on the assumed fuel supply (see Sections II.B.4, and II.B.5, above). The Siting Board finds that the environmental advantage of the GOCC alternative does not outweigh its cost and reliability disadvantages relative to the proposed project. Accordingly, based on the foregoing, the Siting Board finds that the proposed project is superior to the GOCC alternative with respect to providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

With respect to the NGCC alternative, the Siting Board found that the NGCC alternative would be preferable to the proposed project with respect to environmental impacts while the proposed project would be preferable to the NGCC alternative with respect to cost. Further, the Siting Board has found that the proposed project would be comparable to the NGCC alternative with respect to reliability, noting that while a 365-day firm gas supply is not typical, it is a realistic approach which is likely to be both financeable and viable.

In determining that the NGCC alternative would be preferable to the proposed project with respect to environmental impacts, the Siting Board specifically found that the NGCC alternative would be preferable with respect to air quality, water supply and wastewater, noise, solid waste and land use impacts. In addition, the Siting Board could make no finding regarding the relative fuel transportation impacts of the two technologies.

In considering the overall environmental impacts of the two technologies, the Siting Board noted that the advantage of the NGCC alternative was limited with respect to solid waste and wastewater impacts. Thus, the impact areas in which the NGCC alternative has a significant advantage relative to the proposed project are air quality, water supply, noise and land use. However, we have also found that the proposed project would have a significant cost advantage. Therefore, the Siting Board must weigh the environmental benefits of the NGCC alternative against the cost benefits of the proposed project to determine which would be superior. In order to do so, we must first assess the relative value of these benefits. The Siting Board notes that such an assessment was not necessary in comparing the proposed project to the other alternatives in light of the clear overall superiority of the proposed project.

In assessing the environmental impacts of the two technologies, the Siting Board first reviews the air quality impacts of the two technologies with respect to the amount of pollutants that would be emitted, local air quality impacts and regional air quality impacts. With regard to the amount of pollutants that would be emitted, the Siting Board notes that, relative to the proposed project, the NGCC alternative would emit significantly less for all pollutant categories.[245] In addition, considering the potential improvement in the heat rate of the NGCC alternative, the NGCC emissions could further decrease. See Section II.B.3.b., above.

With respect to air quality impacts resulting from the above emissions, the Company has provided analyses addressing the local Taunton area impacts, as well as broader impacts in Massachusetts and New England as a whole. For the local area, the Company's refined air quality modeling analysis for the proposed project reflected existing concentrations of criteria pollutants in the Taunton area that are well within NAAQS. Further, the Company's analysis indicates that the impacts of the proposed project and the NGCC alternative on ambient concentrations of criteria pollutants are three percent or less for all criteria pollutants under all averaging periods with the exception of 24-hour PM-10 for the proposed facility which would be less than ten percent of NAAQS. The emissions from the NGCC alternative would be equal to those from the proposed project for annual NOx, and less than one-fourth those from the proposed project for 3-hour, 24-hour and annual SO_2, for 1-hour and 8-hour CO, and 24-hour and annual PM-10. See Section II.B.3.b.i., above.

The record also indicates that emissions of criteria pollutants from the proposed project and the NGCC alternative also potentially would affect air quality problems that are regional or global in scale -- notably, ground-level ozone and acid rain. Ozone is formed in the atmosphere from emissions of NOx and VOCs, and is of particular concern given that all of

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[245] Specifically, relative to the proposed project, the NGCC alternative would emit: (1) approximately 13 percent of the NOx emissions, or 741 tpy less; (2) approximately 2 percent of the SO_2 emissions, or 1,280 tpy less; (3) approximately 14 percent of the CO emissions, or 633 tpy less; (4) approximately 35 percent of the VOC emissions, or 22 tpy less; (5) approximately 17 percent of the PM-10 emissions, or 85 tpy less; and (6) approximately 52 percent of the CO_2 emissions, or 556,873 tpy less.

Massachusetts is classified as non-attainment for that pollutant. Acid rain also results from NOx emissions, as well as from SO_2 emissions. In addition, the possible impact of CO_2 emissions is a global air quality concern. Here, the Company has proposed a NPV $650,000 program of tree planting and open space conservation which will result in offsets not currently required under state or federal environmental statutes.

Also of significance to regional and global impacts, the Company provided a five-year dispatch analysis that compared emissions from the proposed project to emissions from existing generating facilities that would be displaced by the proposed project. The analysis indicated that the proposed project would produce significantly lower emissions per kwh of important pollutants -- notably NOx and SO_2 -- than many existing generating units. The Siting Board has found, in addition, that the Company's dispatch analysis establishes that the proposed project likely would provide short-term air quality benefits for Massachusetts based on modeled dispatch effects.[246] See Section II.A.4.e.ii.(c), above.

In regard to water supply impacts, while the NGCC represents approximately 59 percent of consumptive use of the proposed project and could use even less if future NGCC facilities are required to use dry low-NOx technologies, the record demonstrates that the water supply impacts of the proposed project at the primary site are minimized (see Section III.C.2.a.iii, below). Specifically the record demonstrates that the proposed project will not have adverse impacts on streamflow or water quality and that impacts to wetlands will be minimized at the primary site for the proposed project. See Section III.C.2.a.ii, below.

In regard to land use, the record demonstrates that the NGCC would require 13.5 acres less of the 25-acre active site than the proposed facility, a significant difference given the proximity of local residences and the lack of land available to buffer noise and visual impacts. The record further demonstrates significantly greater potential for adverse property value impacts than in previous generating facility reviews. Therefore, in Section III.C.2.c, below, in

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[246] In addition, the Siting Board found that the Company's dispatch analysis does not establish that the project would provide significant long-term air quality benefits based on the modeled dispatch effects (see Section II.A.4.e.ii.(c), above).

addition to mitigation proposed by the Company, i.e., construction of a berm and planting of trees and other vegetation for buffering, the Siting Board, has required that SCE offer property owners a property value guarantee program or other method of compensation for adverse property value impacts of the proposed project at the primary site.

In regard to noise, as noted in Section II.B.3.d, above, the proposed project and NGCC alternative present comparable levels of continuous noise at the primary site. Further, in Section III.C.2.c, below, the Siting Board has required SCE to provide an acceptable approach to mitigation of residential noise impacts resulting from rail transportation of coal, including noise from idling locomotives, for the proposed project at the primary site.

Turning to a comparison of the cost of the proposed project and the NGCC alternative, the Siting Board has found that the levelized cost, in 1997 dollars, of the proposed project would range from 81.45 $/MWh to 87.23 $/MWh when evaluated over a 30-year period.[247] Further, the Siting Board has found that, if SCE's assumed heat rate for the NGCC alternative is reduced to reflect the lowest likely heat rate based on a recently proposed NGCC facility, and corresponding levelized costs are reduced by 3.5 percent, then levelized costs for the NGCC, in 1997 dollars, range from $96.02 $/MWh to $110.78 $/MWh.[248]

In comparing cost differences on an annual basis, the Siting Board notes that the availabilities assumed are 85 percent for the proposed project, and 86.8 percent for the NGCC

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247 As noted in Section II.B.4, above, the Company provided cost analyses over 20-year, 30-year and 40-year periods. For purposes of comparison, the Siting Board considers costs over 30 years as representative of a reasonable time frame for facilities such as the proposed project and alternative technologies. The record indicates that over 20 years, levelized costs for the proposed project in 1997 dollars would range from 79.02 $/MWh to 85.33 $/MWh, whereas for the NGCC alternative, assuming the lowest likely heat rate, costs would range from 88.24 $/MWh to 101.42 $/MWh. Over 40 years, levelized costs for the proposed project in 1997 dollars would range from 83.59 $/MWh to 89.57 $/MWh; for the NGCC alternative, again assuming the lowest likely heat rate, costs over 40 years would range from 102.89 $/MWh to 118.98 $/MWh.

248 If, as noted above, the NGW fuel forecast is assumed, then all costs increase for the NGCC alternative for all years.

alternative.[249] Therefore, annual levelized cost in 1997 dollars for the proposed project would range from $90,971,505 to $97,427,187, and annual levelized costs for the NGCC alternative would range from $109,512,951.70 to $126,352,631.70. Comparing consistent cost assumptions, the difference in annual levelized costs of the NGCC alternative and the proposed project in 1997 dollars would range from $18,541,446.70 under low fuel assumptions to $29,059,472.70 under high fuel assumptions. Thus, the annual levelized cost of the NGCC alternative would represent a 20.4-to-29.9 percent increase over the annual levelized costs of the proposed project under the most conservative set of assumptions (i.e., lower NGCC availability, lower NGCC heat rate, and the SCE fuel forecast).[250,251]

Each technology, therefore, offers a significant advantage relative to the other. In order to determine whether the proposed project or the generic NGCC alternative is superior, as directed by the Court, the Siting Board must weigh the environmental benefit of the NGCC alternative against the cost benefit of the proposed project. Specifically, the Siting Board must weigh the air quality, water supply, noise and land use impacts of the proposed project relative to the NGCC alternative against the 20.4 percent to 29.9 percent annual levelized cost benefit of the proposed project relative to the NGCC alternative. In a prior decision, the Siting Board

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249 While 86.8 percent availability likely is low for an NGCC facility, the impact of increasing the availability to 92 percent would be to increase further costs of the NGCC alternative relative to the proposed project and the resulting differences between the NGCC alternative and the proposed project. Thus, 86.8 percent availability represents a conservative assumption.

250 The Siting Board notes that with the Company's heat rate and a 40-year analysis period, the NGCC alternative could represent an increase in annualized costs over the proposed project of between 30.3 percent and 40.6 percent.

251 As discussed in Section II.B.4., above, the Siting Board recognizes that the cost of the NGCC alternative represents the high end of the likely range of costs for a natural gas-fired facility due to reliance on a 365-day firm gas supply. However, as also noted above, the Company's cost analysis is conservative with respect to the cost of the proposed project in relation to the NGCC alternative in that the capital cost of the proposed project includes project-specific costs that were not included for the NGCC alternative.

was faced with a similar conflict of the statutory objectives of environmental impact and least cost in the comparison of alternative technologies. See, EEC (remand) Decision, 1 DOMSB at 387-390. In that decision the Siting Board determined that in order to indentify the appropriate means to weigh or balance these objectives, we must look to the language of our statute for guidance. Id. at 390.

In reviewing the statute in that decision, the Siting Board found (1) that to be consistent with the mandate of the statute, the focus of any analysis, weighing or balancing must be the Commonwealth's energy supply, and (2) that any analysis, weighing or balancing undertaken in providing a necessary energy supply must be done in a manner that is consistent with implementing the policies of the statute. Id.

In reviewing Sections 69H to 69Q for relevant policies, the Siting Board noted that the policies implicit in these sections dictate that the Siting Board must determine that electric companies have reliable sources of energy to ensure the Commonwealth's electricity consumers a necessary energy supply[252] and that the Siting Board has the authority to accept increased environmental impacts or costs[253,254] if justified for purposes of providing a necessary energy

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252 The Siting Board also notes that another policy contained in our statute requires the Siting Board to determine that plans for the expansion and construction of new facilities are consistent with current health, environmental protection, and resource use and development policies as adopted by the Commonwealth. G.L. c. 164, § 69J.

253 G.L. c. 164, § 69K provides the Siting Board with the authority to override a standard imposed by a state or local agency that prevents an electric company from meeting that standard with commercially available equipment or if such agency inappropriately delayed any necessary approval, consent, permit or certificate. G.L. c. 164, § 69R allows the Siting Board to approve a petition of an electric company for the right to exercise the power of eminent domain over land interests necessary for the construction of an energy facility. Thus, the Siting Board's statute provides tools for the Siting Board to use in order to provide necessary energy resources in the event that an environmental, safety, land use, or other issue prevents the construction or operation of a facility.

254 In City of New Bedford, the SJC noted that the Siting Council must explicitly state the basis of its determination, with adequate subsidiary findings to support its conclusions.

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supply that is reliable.[255] Id. at 391-392. Therefore, in implementing the policies contained in the Siting Board statute, the Siting Board found that as the existing energy supply has associated environmental impacts, costs, and reliability considerations, any proposed addition to the Commonwealth's energy supply must be considered in light of the existing mix of energy resources and the environmental impacts, costs and reliability of that mix. Id. at 392. The Siting Board, therefore, concluded that it must determine, the relative value to the Commonwealth's energy supply of the specific environmental impacts and costs of the proposed project and the NGCC alternative in that case in light of the existing mix of resources. Based on the relative values of these benefits the Siting Board was able to determine the appropriate weight which should be applied in the balancing of the statutory objectives. Id. at 392-396.

As the Siting Board noted in the EEC (remand) Decision, a reliable energy supply is one that among other things, will not be unduly restricted due to interruptions in supply of fuel resources.[256] 1 DOMSB at 392. A fuel supply that is overly dependent on one type of fuel, similar to an electric company plan that is overly dependent on one or a few energy resource options, could prevent the provision of necessary energy during times when that fuel supply was restricted. A fuel supply which lacks diversity (i.e., is overly dependant on one type of fuel) would be vulnerable to reduced reliability. Thus, consistent with our review in the EEC

254(…continued)
413 Mass. at 491. The SJC's directive that the Siting Council must balance environmental impacts and costs implies that the Siting Board could determine that cost outweighed environmental impacts provided that the basis for such a determination was explicit and consistent with statutory objectives.

255 Such a conclusion is also consistent with the Siting Commission's Third Report in which they indicate that the proposed siting bill sought to mitigate environmental challenges which were perceived as delaying new and needed capacity (Third Report at 8, 9, 15). Further, the Siting Commission sought to address concerns that devices required for environmental protection and enhancement would reverse the long-term trend of decreasing average costs for electricity (id.).

256 The Siting Board notes that other issues relative to the reliability of the electric energy supply as a whole include transmission and distribution system reliability.

(remand) Decision, the Siting Board here reviews the fuel supply underlying the Commonwealth's energy supply to identify reliability considerations relevant to a comparison of alternatives.[257]

As indicated in the EEC Decision, in 1989, Massachusetts depended on oil-fired generation to meet 49 percent of its electric power needs. 22 DOMSC at 289. Further, as of January 1, 1990, less than 13 percent of the Commonwealth's generating capability was provided by coal and in 1989, 12 percent was provided by natural gas. Id. In the EEC Decision, the Siting Council stated that, despite the concerns raised by the proponent in that case regarding the increased reliance on natural gas in the state and region and the associated issues regarding the availability and price of gas,[258] "the significant environmental benefits of gas as a fuel for both power generation and other uses, and the minimal percentage of gas currently present in the state's and region's fuel mix, suggests that the region is a long way from any risk of overdependence on gas." Id. at 293. However, the Siting Council went on to say "that diversity cannot be achieved by reliance on additions of just one fuel type or one technology. Even if sufficient new gas-fired facilities could be constructed and placed in operation in time to meet all of the region's need for additional capacity, elimination of alternative options still would be unwise. Clearly, both Massachusetts and the region need to increase their reliance on as many types of non-oil supply options as possible while maintaining an appropriate balance between cost, environmental impacts and reliability." Id. at 293-294. In conclusion, the Siting Council agreed with EEC "that the addition of the proposed project

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[257] The Siting Board notes that the Siting Council recognized diversity as an important factor in achieving both a reliable and least-cost energy supply throughout reviews of both facility and utility forecast/supply plan reviews. See, e.g., Massachusetts Electric Company and New England Electric System, 18 DOMSC at 336, 363-365 (1989); Eastern Utilities Associates, 18 DOMSC at 100, 131 (1989).

[258] The proponent raised concerns relating to gas price ties to oil price in new long-term gas contracts. EEC Decision, 22 DOMSC at 290.

generally would enhance the diversity of the state's and the region's power generation resource mix." Id. at 295.[259]

A review of the 1992 CELT report (Exh. EFSC-N-61A) indicates that, although the contribution from natural gas-fired generation to both the Massachusetts and regional energy supply as a result of new gas-fired generating resources has continued to increase, the contribution of coal-fired generation is decreasing.[260] Further, the 1992 CELT report indicates significant potential to increase gas-fired generation in Massachusetts and the region through the conversion of existing oil/gas dual-fuel units to primarily gas-fired units. The Siting Board notes that such conversions would be consistent with the energy and environmental policies in

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259 The Siting Board notes that this discussion of diversity was in Section II.B.2. of the EEC Decision regarding consistency with policies of Commonwealth. In noting the Siting Council's statements, the Siting Board is not attempting to elevate the issue of consistency with policies over a balancing of environmental impacts, cost and reliability in meeting the need for additional energy resources; rather, the Siting Board recognizes that a balancing of the statutory objectives must be done in a way that is consistent with the policies of the Commonwealth.

260 With respect to new gas-fired facilities, the Siting Board notes that over the last six years the Siting Council and Siting Board have approved seven such facilities (approximately 1,400 MW combined), and that the Siting Board has approved the site banking of one additional facility (306 MW).

With respect to new coal-fired facilities, the Siting Board notes that this is the second coal-fired project to be reviewed by the Siting Council or Siting Board, and that the conditional approval of the first project is currently under appeal. However, the Siting Board is aware of one 20 MW coal-fired project that was recently constructed in Massachusetts of which all the power was sold to a New Hampshire utility. See Turners Falls Limited Partnership, 18 DOMSC 141 at 144 (1988). In addition, the AES Thames facility is a 180 MW coal-fired project, recently completed in Connecticut, power from which will be sold to Northeast Utilities for distribution to its subsidiaries, some of which provide power to Massachusetts customers (Exh. EFSC-N-61A). Finally, a recent Massachusetts D.P.U. decision approved an Offer of Settlement, which, in effect, resulted in the buy out of contracts with 11 Massachusetts utilities of a 72.5 MW coal-fired project proposed for construction in Rhode Island (Newbay). The Siting Board notes that the decision in D.P.U. 88-265A raises significant questions as to the continued viability of the Newbay project. See, D.P.U. 88-265A, Review of Purchase Power Contracts.

response to the Clean Air Act and could be accomplished without the need for significant facility modifications or additional generating facility siting review. Despite the increase in gas-fired generation experienced in the state and region thus far, the Siting Board recognizes that there is still a need for additional gas-fired generation for system-wide reliability purposes. Similarly, the evidence with regard to the rate at which new gas-fired generation and new coal-fired generation are being added to the state's and region's mix of energy resources indicates that there is an even greater need to add low-cost, environmentally-sound, coal-fired generation for system wide reliability purposes.[261,262]

The Siting Board has found, based on the record in this proceeding, that the proposed project is preferable to both the CGCC and PC alternatives with respect to both cost and environmental impacts. See Sections II.B.3., and II.B.4, above. Further, the proposed project includes significant environmental mitigation measures as described herein and will be required to provide further mitigation in the areas of air quality, noise, visual, land use, and rail transportation impacts. See Section III.C.2.c., below. In addition, the proposed project has been shown to be the least cost approach to meeting the need relative to the alternatives reviewed. See Section II.B.4, above. The Company's dispatch analysis further demonstrates that the proposed project offers significant short-term environmental benefits relative to existing generating units. See Section II.A.4.e.ii, above.

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261 The Siting Board notes that the legislature has expressly recognized the value of coal-fired units in reducing dependency on oil. <u>See</u>, G.L. c. 164, §95G1/2. That statute, first enacted in 1980 (St. 1980, c. 464), has been repeatedly amended, including an amendment as recent as 1990 (St. 1984, c. 395, §1; St. 1986, c. 557, § 146; St. 190, c. 177, §350). The Siting Board notes that such action by the legislature supports the inference that the use of coal, with environmental safeguards, is appropriate as a part of the fuel mix to provide necessary energy to the Commonwealth and to decrease the Commonwealth's dependence on oil.

262 The Siting Board here is not making a determination as to what the ultimate levels of gas or coal should be in the Commonwealth's energy supply mix, but rather is indicating that the Commonwealth has not yet reached such ultimate levels.

While the Siting Board has found that the NGCC alternative offers greater environmental benefits to the energy supply relative to the proposed project, the Siting Board has also found that the proposed project offers greater cost benefits to the energy supply, and comparable reliability benefits, relative to the NGCC alternative. Further, the Siting Board finds that the increases in state and regional reliance on natural gas reduces the value to the energy supply associated with the environmental benefits of the NGCC alternative relative to the value to the energy supply associated with the cost and reliability benefits of the proposed project. Therefore, the Siting Board finds that in balancing the specific environmental impacts and costs of the proposed project against those of the NGCC alternative, in light of the environmental, cost and reliability characteristics of the existing energy supply, it is appropriate to give more weight to the specific cost benefits offered by the proposed project relative to the specific environmental benefits offered by the NGCC alternative. As such, the Siting Board finds that the cost benefits of the proposed project outweigh the environmental benefits of the NGCC alternative. The Siting Board further finds that, on balance, the proposed project is superior to the NGCC alternative with respect to providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

b. Findings and Conclusions

The Siting Board has found that:

- the proposed project is superior to the CGCC alternative with respect to providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost;
- the proposed project is superior to the PC alternative with respect to providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost;
- the proposed project is superior to the RO alternative with respect to providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost;

- the proposed project is superior to the GOCC alternative with respect to providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost;
- in balancing the specific environmental impacts and costs of the proposed project against those of the NGCC alternative, in light of the environmental, cost and reliability characteristics of the existing energy supply, it is appropriate to give more weight to the specific cost benefits offered by the proposed project relative to the specific environmental benefits offered by the NGCC alternative; and
- on balance, the proposed project is superior to the NGCC alternative with respect to providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

Accordingly, based on the record in this proceeding, the Siting Board finds that the Company has established that the proposed project is superior to all alternative technologies reviewed with respect to providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

C. Project Viability

1. Standard of Review

The Siting Board determines that a proposed non-utility generating project is likely to be a viable source of energy if (1) the project is reasonably likely to be financed and constructed so that the project will actually go into service as planned, and (2) the project is likely to operate and be a reliable, least-cost source of energy over the life of its power sales agreements. Cabot Power Decision, 2 DOMSB at 358; Altresco Lynn Decision, 2 DOMSB at 136-137; NEA Decision, 16 DOMSC at 380.

In order to meet the first test of viability, the proponent must establish (1) that the project is financiable, and (2) that the project is likely to be constructed within the applicable time frames and will be capable of meeting performance objectives. In order to meet the second test of viability, the proponent must establish (1) that the project is likely to be operated and maintained in a manner consistent with appropriate performance objectives and (2) that the proponent's fuel acquisition strategy reasonably ensures low-cost, reliable energy resources over the terms of the power sales agreements. Cabot Power Decision, 2 DOMSB at 358; Altresco Lynn Decision, 2 DOMSB at 137; Altresco-Pittsfield Decision, 17 DOMSC at 378.

Here, SCE has argued that the project fully meets each of the Siting Board's viability tests, and that the proposed project will be a viable source of energy (SCE Brief at 127 through 128).

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. Here, SCE indicated that CEI would be the lead party responsible for arranging financing for the proposed project (Exh. SCE-1, at 7-1). SCE asserted that the comprehensive financing experience of CEI, expected favorable debt coverage ratios ("DCRs") for the project under a variety of conservative assumptions, and the proposed use of a flexible financing and marketing strategy, demonstrate that the TEC is financiable (id. at 7-5).

SCE stated that it is composed of the affiliates of three well-respected, experienced power generating companies, CEI, PG&E/Bechtel and CSC (see Section I.A, above) (id. at 2-1). In regard to financing experience, SCE reported that CEI has developed working relationships with major lending institutions and has been actively involved in financing over $1.3 billion in energy projects (id. at 2-5). SCE stated that CEI has an extensive in-house staff of financial analysts, who completed over $800 million in new financing and refinancing in 1990 (id.). Further, CEI is an owner in twenty-four energy projects that are either in operation or under construction, comprising 706 MW of total capacity and a total investment of $2.26 billion (id., Table 2.1). Finally, SCE described CEI's balance sheet as incorporating a healthy mix of liquid assets and long-term project investments, with assets of approximately $1 billion (id. at 2-2).

SCE stated that the participation of PG&E/Bechtel provides financial strength to the project which results from the diverse experience and resources of its two parent companies - PG&E and Bechtel (id. at 2-6). SCE asserted that PG&E, developer, owner and operator of over 15,000 MW of capacity, is the largest combined gas and electric investor-owned utility in the nation (id. at 2-7). The Company provided information indicating that PG&E has approximately $20 billion in assets and operations (id.). SCE reported that Bechtel has built more than 400 power plants world-wide, with a total capacity of more than 225,000 MW -- equal to one-third of the generating capacity in the United States (id.). In terms of financing, SCE stated that Bechtel maintains an experienced in-house finance subsidiary, Bechtel Financing Services, Inc., which has arranged for over $9 billion in project financing in the last 20 years, including $5-6 million in projects in the last year (id.; Tr. 5, at 156).

The Company indicated that DCRs are a generally accepted measure of the financial attractiveness of a proposed energy project (Exh. SCE-1, at 7-2). SCE asserted that recent energy financings have shown that lenders require average coverage ratios of approximately 1.35 with the lowest annual ratio being at least 1.25 and a debt-to-equity ratio no higher than 85 percent to 15 percent (id.). The record indicates that SCE has assumed a debt-to-equity ratio of 83 percent to 17 percent throughout all of the financial analyses (id. at 7-2, 7-4). Mr. Roberts reported that the highest equity level to which the partners would commit to is based on a variety of factors which are situational and time dependent (Exh. EFSC-RR-96).

To support its assertions of adequate DCRs for financing, the Company provided pro formas under scenarios involving a range of capital costs, varying costs for coal, and different mixes of capacity sold under long-term contracts (Exhs. EFSC-V-10; EFSC-V-11; EFSC-V-21; EFSC-RR-92).[263,264] The pro formas presented by the Company detailed the DCRs and an

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263 The base case pro forma assumes that 100 percent of the TEC capacity will be sold by the commercial operation date (Exh. EFSC-V-9). The two pro formas reflecting lower levels of capacity sold under long-term sales assume sales of 100 MW (66.6 percent) and 75 MW (50 percent), respectively (Exh. EFSC-V-10).

264 The Attorney General requested additional pro forma scenarios from the Company,
(continued...)

internal rate of return ("IRR") for each scenario. The Company indicated that DCRs are scrutinized by the lender and IRRs are determined to some degree by the equity investors (id.).

The record indicates that based on sensitivity analyses of its pro formas, the base case, the low capital cost case, and the low and high coal cost cases met the stated DCR and IRR parameters (id.). The record further indicates that neither of the pro formas detailing the low-capacity, long-term power sales meet the DCR or IRR parameters, and would require large contributions of equity (Exh. EFSC-V-10).[265] The high capital cost case, which assumed a $15 million increase in construction costs, would necessitate a higher contribution of equity totaling 23 percent; however, the Company indicated that it would be willing to fund the project at this equity level (Exhs. EFSC-V-21; EFSC-RR-96; Tr. 21, at 168).

The Company provided a schedule for issuing a financing memorandum, the first step in the process for selecting the lender(s), and finalizing the loan agreement (Exh. EFSC-V-23). SCE stated that it anticipates developing the memorandum five to six months prior to financial closing, which takes into account a 30-day lender response time and a four to six month negotiation schedule (id.).[266] SCE stated that while it would be considering all financing options before finalizing its financing package, it currently is considering a combination of

(…continued)
consisting of a high-case fuel scenario that reflected a 6 percent escalation in the cost of coal, and a lower heat rate scenario (Exhs. AG-RR-24; AG-RR-25). The Company indicated that under these assumptions, the project economics were still very good and met the requisite parameters (id.; SCE Brief at 132).

265 Mr. Montgomery stated that the Company would not proceed to financial closing without a high degree of certainty that all remaining capacity would be sold during the construction period (Tr. 5, at 208).

266 SCE originally stated that it expected the project to undergo financial closing at the end of 1992, with the plant ready for operation in January 1996, however, SCE up-dated the timetable to reflect a financial closing date projected to occur no earlier than January 1993 and as late as the Fall of 1993 (Exhs. EFSC-V-22; EFSC-V-23; Tr. 8, at 62). Mr. Roberts indicated that construction would begin within 30 days of financial closing, whereby a financial closing in the Fall of 1993 would bring the facility on-line in late 1996 or early 1997 (Tr. 21, at 169).

shorter term maturity bank debt and longer term maturity insurance company debt as the most attractive scenario (Exh. EFSC-V-13). The Company reported that it will be developing a lender list, drawing on a list of potential lenders presently being prepared for another project (Tr. 21, at 169 through 170). Further, Mr. Roberts indicated that in prior meetings with financial institutions and lenders relating to other projects or concerning general marketing efforts, the TEC project has been favorably received (id. at 170 through 171).

Finally, the Company presented its marketing strategy indicating that it has focused first, on selling power to municipal electric utilities that have a need for fuel diversification or have current contracts that are due to expire; second, on responding to electric utility Requests for Proposals ("RFPs");[267] and third, on negotiating contracts with investor-owned utilities (Exh. EFSC-MB-7). SCE noted that it has a signed PPA with TMLP for 30 MW[268] (Exh. SCE-1, at 4-2). The Company provided analyses of the project costs of the TEC relative to the avoided costs of several Massachusetts utilities (Exh. SCE-2BR, app. C). These analyses indicate that the Company would be able to offer its power at or below the utilities avoided costs (id.).

The record indicates that the project proponents have extensive financial experience and strength as a result of participation by CEI and PG&E/Bechtel. Further, the record indicates that the Company's equity participants are willing to be flexible in the amount of equity contribution under a variety of scenarios providing a degree of flexibility while

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267 SCE stated that it was concerned about the outcome of the IRM externality process (Exh. EFSC-MB-7). (See, Investigation as to the Environmental Externalities to be Used in Resource Cost-Effectiveness Tests, D.P.U. 91-131 which has been appealed and is currently pending before the SJC.) However, Mr. Roberts stressed that another factor considered in the IRM process is diversity, and added that coal would be a positive addition to a utilities' fuel mix (Tr. 8, at 102). In sum, he stated that SCE's decision as to whether it would submit bids in response to individual Massachusetts utilities IRM RFPs will depend on the assigned values for such factors as emissions offsets and supply diversity (id. at 107). Finally, Mr. Roberts asserted that the project is marketable even without selling to Massachusetts investor-owned utilities (id. at 104).

268 Approval of the signed PPA is pending before the Department. See, D.P.U. 91-273/92-273.

enhancing the ability to finance the project. In additon, the Company's pro formas indicate that SCE would be able to offer its power at or below several Massachusetts utilities' avoided costs -- a necessity in signing additional long term PPAs under several scenarios.

Despite these factors which indicate significant potential for financing, the Siting Board notes two issues underling the Company's financial analysis which raise serious questions regarding the Company's actual ability to finance the project as planned. First, the Siting Board notes that all of the Company's financial analyses assume production and sale of steam for use in the proposed CO_2 production facility. Specifically, the Company stated that the pro formas reflect anticipated revenue received from proposed steam sales to the CO_2 plant as well as the production cost requirements of making available the steam for such sales (Tr. 8, at 167). However, the Company stated that the capital costs of the CO_2 plant are not included in the pro formas because any capital costs incurred by SCE would be immediately recovered when the CO_2 plant is sold (Tr. 8, at 167 through 186).[269] The Company stated that the plant would be viable as it would provide New England users of CO_2 with a lower cost supply option (id. at 68). However, SCE asserted that the viability of its overall project would not be impacted if the CO_2 plant was cancelled (Exh. EFSC-V-14).[270] SCE further stated that if the CO_2 plant is not constructed, the Company would possibly proceed with the TEC in the form of an Independent Power Producer ("IPP"), should the regulatory environment change (Exhs. EFSC-V-14; EFSC-S-2; EFSC-S-9).

While the Company apparently believes that viable construction and operation of the CO_2 plant would have a limited impact on the viability of the overall project, we cannot agree

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269 The Company stated that under FERC regulations, SCE cannot own and operate the CO_2 plant and that SCE would have to recover from the buyer the capital costs plus the interest on the amount expended in the construction of the CO_2 plant (Tr. 8, at 162, 165). The Company asserted that SCE would insure that there is a buyer for the CO_2 plant and for the CO_2 before commencing with construction (id. at 165 through 166).

270 The Company stated that the CO_2 plant is about 6-7 percent of the overall project cost and has a return of investment that is in the same range as the power plant (Exh. EFSC-V-14).

that the viability of the CO_2 plant is irrelevant to the viability of the proposed project. As an initial matter, we note that the project is proposed as a cogeneration facility. As such, the analysis of the proposed project in this decision is based on such status (see Section III.B, below). Thus the findings contained herein are, in part, based on the cogeneration status of the proposed project. Further, the marketing strategy presented by the Company assumes that the TEC will be a QF under PURPA. Status as an IPP could significantly alter the Company's ability to sell in certain markets.

In past reviews of cogeneration projects, the Siting Board has been able to evaluate the viability of a proposed generation project based, in part on signed steam sales agreements with clearly viable steam hosts. Here, the Company has failed to provide any evidence with respect to potential purchasers of the CO_2 facility or its CO_2 output. Thus, the Siting Board cannot evaluate what impact steam sales to the CO_2 plant will have on project financiability or overall viability. Therefore, in order to ensure that the proposed project is viable, the Siting Board requires the Company to provide evidence of a steam sales agreement with an appropriate entity (CO_2 plant owner) prior to the commencement of construction.

Second, SCE has presented a number of scenarios which address the sensitivity of project finances to capital costs, cost of fuel, and the amount of capacity sold under long-term contracts. The range of assumptions provided by SCE, including SCE's base case assumptions, is generally reasonable. The results of these sensitivity analyses indicate that the SCE project is financiable based on projections of DCRs across a broad array of scenarios with the exception of the scenario of limited capacity under long-term power sales. Although the Company has indicated that the use of pro formas encompassing limited long-term power sales is not relevant since SCE has until the close of construction to secure contracts, the Siting Board notes that the assumed level of capacity under long-term contracts is the pro forma variable most likely to affect financiability, and, as such, appears to contribute a high degree of uncertainty as to whether the TEC moves forward.

Clearly, SCE needs to market a significant portion of its capacity to be financiable. We note, however, that in Section II.A.5.c, above, the Siting Board was unable to find need for the proposed project prior to the year 2000. Therefore, the Siting Board required SCE to submit signed and approved PPAs for at least 75 percent of the proposed projects' electric output to establish need at an earlier time. The Siting Board notes that in light of the uncertainty of need in the early years of planned facility operation, it may be difficult for the Company to market a sufficient portion of its capacity to be financiable. Nevertheless, we recognize that if SCE complies with the condition regarding a steam sales agreement and the condition regarding PPAs, the Company will be able to ensure that the proposed project is financiable.

Based on the foregoing, the Siting Board finds that upon compliance with the above condition regarding steam sales and the condition in Section II.A.5.c, above regarding PPA's, SCE will have established that its proposed project is financiable.

b. Construction

In considering a proponent's construction strategy for a proposed project, the Siting Board considers whether the project is reasonably likely to be constructed and go into service as planned. Here, SCE indicated that the energy purchase agreement between TMLP and SCE, specifies that Bechtel Construction Inc. ("BCI"), an affiliate of BPC, would be the engineering, procurement, and construction ("EPC") contractor (Exhs. EFSC-V-15; SCE-2A, app. A). The Company stated that the broad scope of the EPC contract would establish responsibility with BCI for the performance of the detailed design, construction, start-up, and testing of the facility (Exh. SCE-1, at 7-6).[271] SCE added that many of the complexities involved with negotiating an EPC contract were significantly reduced due to Bechtel's initial involvement in the development and permitting of the facilities (Exh. EFSC-V-15).

SCE explained that the EPC contract forms the parameters for the development schedule, and would assure economic feasibility, project financiability and plant performance related to achieving output, efficiency targets, and permit requirements (id.).

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[271] The Company has provided a draft EPC contact (Exh. EFSC-V-15).

SCE stated that the EPC contract will contain a set of binding terms and conditions for the engineering and construction of the proposed TEC facility, including provisions for: (1) a lump sum price; (2) a guaranteed schedule; (3) early completion incentives; (4) liquidated damages for non-performance; (5) construction lender design review; (6) construction lender monitoring; (7) performance tests; and (8) arbitration (id. at 7-6 and 7-7; EFSC-V-15A). The Company explained that, although it assumed a 34 to 36 month construction schedule, experience with other CFB boilers and discussions with vendors indicated that a 30 to 34 month construction schedule is achievable (Exhs. EFSC-V-6; EFSC-V-12).[272]

SCE asserted that BCI is eminently qualified to provide EPC services for the proposed facility, as it has been the leading engineering and construction company to the electric utility industry for nearly 50 years (Exh. SCE-1, at 2-7). In addition, SCE stated Bechtel has completed more than 20 cogeneration projects in the last ten years, ranging in capacity from 1 MW to 200 MW (id. at 7-7).[273] Further, SCE identified the close working relationship that Bechtel has with CEI and PG&E as their engineering and construction contractor for other projects (id. at 2-6).

In terms of the facility site and access arrangements, the Company provided three executed contracts between SCE and TMLP (id. at 7-10). The first agreement was the pre-lease agreement, which provides SCE with access to the property during project permitting, site inspections, surveys, and title searches (Exhs. SCE-2A, App. E; SCE-18, at 2). The second document, the lease agreement, commencing in January 1991, provides SCE with the property rights to the site for a term of 40 years (Exhs. SCE-2A App. F; SCE-1, at 7-10). Lastly, the general services agreement provides for access to easements associated currently

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[272] The Company provided a 37 month detailed overall construction and start-up schedule which also included all required performance and environmental tests (Exh. EFSC-V-12).

[273] SCE noted that Bechtel's major cogeneration and alternative energy projects, include the SEMASS project in Massachusetts, the Mt. Poso Project in California, the Gilberton Project in Pennsylvania, and the Colstrip Power Plan in Montana (Exh. SCE-1, at 2-4 and 2-8).

with TMLP's existing power plant site, and runs for the term of the lease agreement (id. app. G; id.).

The Company stated that the existing energy power purchase agreement between SCE and TMLP fulfills all requirements for the TEC to go on line as a NEPOOL dispatchable facility (Exhs. EFSC V-20; EFSC V-20S). Specifically, the Company stated that the power purchase agreement provides for interconnection of the TEC to the existing switchyard adjacent to the preferred site of the TEC (id.; SCE Initial Brief at 139). The purchase agreement also states that SCE will use its best efforts to try and have the TEC classified as a NEPOOL Planned Facility (Exh. SCE-2A, app. A). The Company stated that EUA and TMLP are conducting detailed load flow and stability studies to determined the impact of the TEC on the regional transmission system (Exhs. EFSC-V-20; EFSC-V-20S). The Company also stated that SCE, via TMLP, instituted separate studies and the preliminary results indicate that the TEC will not adversely effect the regional transmission system and only minor system upgrades are expected (id.; Tr. 18, at 3 through 10; SCE Brief at 140).

With regard to water supply for the proposed TEC, the Company provided a Site Plan review that noted the ability of SCE to obtain water from the City of Taunton (Exh. SCE-15, at 11). Further, SCE provided an analysis indicating that the proposed water withdrawals from the Taunton River meet the requirements for receipt of a MDEP permit under the Water Management Act (Exh. SCE-23, app. E).

In the past, the Siting Board has found that a signed agreement for the design and construction of a proposed project provides reasonable assurances that the proposed project is likely to be constructed on schedule and will be able to perform as expected. Cabot Power Decision, 2 DOMSB at 363; Altresco Lynn Decision, 2 DOMSB at 143; Altresco-Pittsfield Decision, 17 DOMSC at 380. Further, the Siting Board previously has noted that BPC has acquired a noteworthy level of experience as a builder of power plants and cogeneration facilities. EEC Decision, 22 DOMSC at 302; MASSPOWER Decision, 20 DOMSC at 357. Here, SCE has submitted a draft EPC contract. In addition, the record in this proceeding indicates that BPC has significant experience in the design and construction of plants which use the CFB technology proposed for this project and has successfully completed similar projects. The Siting Board notes that the draft contract includes a number of advantageous provisions, such as incentive and penalty terms, which the Siting Board has recognized in previous reviews as ensuring expedient and quality construction projects. If the final EPC contract contains all significant provisions as those in the draft contract, SCE will be able to establish that the proposed project is likely to be constructed within the applicable time frames and be capable of meeting performance objectives. Therefore, the Siting Board requires SCE to provide the Siting Board with a signed EPC contract between SCE and BPC or a comparable entity as evidence of a reasonable assurance that the project is likely to be constructed on schedule and will be able to perform as expected.

The record further indicates that agreements between SCE and TMLP will provide the Company with the necessary access to the TMLP property. However, although the Company has indicated that the existing energy purchase agreement between SCE and TMLP fulfills all of the requirements for the TEC to go on line as a NEPOOL dispatchable facility, SCE has not provided evidence of a signed interconnection agreement with TMLP enabling transmission access. The Siting Board notes that the PPA does not constitute an interconnection agreement which would ensure that the power flows associated with the proposed facility could be accommodated on the regional transmission system. Failure to gain access to the regional transmission system would prevent the proposed project from providing energy to the state and the region. The Company has not provided a written explanation as to why such an agreement is not yet available. However, if SCE provides a signed interconnection agreement, SCE will be able to establish that its proposed project is likely to be capable of meeting performance objectives. Therefore, the Siting Board requires SCE to provide the Siting Board with a signed copy of an interconnection agreement between SCE and TMLP. Accordingly, based on compliance with the above conditions that the Company provide the Siting Board with (1) a signed EPC contract that is the same or similar with regard to all significant provisions as those in the draft EPC contract, and (2) a signed copy of an interconnection agreement between SCE and TMLP for the provision of the proposed project's access to the regional transmission system, the Siting Board finds that SCE 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, upon compliance with the condition relative to steam sales, above, and relative to power sales in Section II.A.5, above, SCE will have established that its proposed project is likely to be financiable. The Siting Board also has found that, upon compliance with the above conditions relative to the signed copy of the EPC contract and assurance of access to the regional transmission system, SCE has established that its proposed project is likely to be constructed within applicable time frames and capable of meeting SCE performance objectives. Accordingly, the Siting Board finds that, upon compliance with the above conditions, SCE will have established that its proposed project meets the Siting Board's first test of viability.

3. Operations and Fuel Acquisition

a. Operations

In determining whether a proposed non-utility generation project is likely to be viable as a reliable, least-cost, source of energy over the life of its power sales agreements, the Siting Board evaluates the ability of the project proponent or other reasonable entities to operate and maintain the facility in a manner which ensures a reliable energy supply. Cabot Power Decision, 2 DOMSB at 364; Altresco Lynn Decision, 2 DOMSB at 145; Altresco-Pittsfield Decision, 17 DOMSC at 381. In a case where the proponent has relatively little experience in the development and operation of a major energy facility, that proponent must establish that experienced and competent entities are contracted for, or otherwise committed to, the performance of critical tasks. These tasks should be enumerated in detailed contracts or other agreements that include financial incentives and/or penalties which ensure reliable performance over the life of the power sales agreements. Cabot Power Decision, 2 DOMSB at 365; Altresco Lynn Decision, 2 DOMSB at 145; Altresco-Pittsfield, 17 DOMSC at 381-382.

Here, SCE stated that the power purchase agreement with TMLP specifies that COSI, a full service operating subsidy of CEI would be responsible for providing O&M services to the proposed facility (Exh. SCE-1, at 2-2). SCE provided a draft copy of a contract between SCE and COSI for O&M services (Exh. EFSC-V-16A). SCE asserted that many of the complexities involved with negotiating an O&M contract were significantly reduced due to COSI's initial involvement in the development and permitting of the facilities (Exh. EFSC-V-16).

The draft O&M contract contains a set of principal terms and conditions for the operation and maintenance of the proposed TEC facility (Exh. EFSC-V-16A). In addition, the primary terms of the agreement specify incentives/penalties for the proposed facility's operation and maintenance (Exh. SCE-1, at 7-19). These incentive/penalties address reliability, economic, technical and environmental performance of the proposed facility over the term of the contract (id.).

SCE asserted that COSI is an industry leader in operating CFB boilers, and is currently operating 11 CFB boilers nation-wide (id. at 2-2). In addition, the Company pointed to COSI's experience in operating a wide range of CFB boilers by different manufacturers and asserted that COSI has been involved in operating seven types of boilers, more than any other O&M firm (id.). Further the Company stated that COSI provides technical expertise for O&M services and project management throughout the power industry, totaling 1025 MW of capacity (id. at 2-2 and Table 7.3).

SCE enumerated COSI's responsibilities both during pre-commercial operation and commercial operation after acceptance (id. at 7-22 through 7-29). Activities during the pre-commercial phase include staffing, delivery and inventory of spare parts, facilities set-up, training, procedures and start-up (id.). The company stated that once the plant has completed its acceptance testing and is deemed commercial, COSI then assumes care and custody of the facility from the EPC contractor for on-going operations (id. at 7-26 through 7-27). Further, SCE stated that operations and maintenance would be conducted on an integrated basis to include work orders, preventive maintenance, outage maintenance, inventory control, and other safe work practices (id. at 7-27).

In past cases, the Siting Board has found that an acceptable, executed O&M contract with an appropriate, experienced entity provided sufficient assurance that a project is likely to be operated and maintained in a manner consistent with reliable performance over the life of its power sales agreements. Cabot Power Decision, 2 DOMSB at 365; Altresco Lynn Decision, 2 DOMSB at 146; Altresco-Pittsfield Decision, 17 DOMSC at 382. Here SCE has provided a draft O&M agreement with COSI, a qualified vendor, complete with bonus, penalty, and incentive provisions similar to those reviewed and approved in other Siting Board decisions. The agreement contains sufficient detail to indicate to the Siting Board that the project is likely to be operated and maintained in a manner consistent with reliable performance over its expected life if signed. If SCE provides an executed O&M agreement, which is identical or similar in all significant provisions provided in the draft form with COSI or comparable entity, the Company will be able to establish that the proposed project is likely to be operated and maintained in a manner consistent with reliable performance over the life of the projected and likely power sales agreements. Therefore, the Siting Board requires SCE to provide the Siting Board with a signed copy of the O&M agreement between SCE and COSI or comparable entity.

Accordingly, based on compliance with the above condition that SCE provide the Siting Board with a signed copy of the signed O&M agreement between SCE and COSI or comparable entity, the Siting Board finds that SCE will have established that the proposed project is likely to be operated and maintained in a manner consistent with reliable performance over the life of projected and likely power sales agreements.

b. Fuel Acquisition

In considering an applicant's fuel acquisition strategy, the Siting Board considers whether such a strategy reasonably ensures low-cost, reliable energy resources over the likely terms of its PPAs.

SCE provided a draft copy of a 20-year contract[274] with a potential coal supplier, acting in the capacity of a coal broker, to provide all necessary coal for the TEC from the Cyprus Emerald Mine ("Cyprus") located in Pennsylvania (Exhs. EFSC-E-33; SCE-12, at 6; Tr. 5, at 110). The Company issued two rounds of coal supply RFPs, one prior to submitting the TMLP RFP and one after TMLP's selection of SCE to proceed with the project (Exh. EFSC-V-3). SCE received responses from a total of ten different suppliers (Exh. EFSC-V-4). SCE stated it established the following requisites for the selection of a fuel supplier: (1) coal and ash to be transported via Conrail; (2) ash to be returned to an out-of-state reclamation facility; (3) coal sulfur content not to exceed 2 percent peak and 1.8 percent average; (4) term of coal supply contracts to be at least 20 years with options for extensions; and (5) pricing escalators to be based on the gross national product implicit price deflator ("GNP-IPD")[275] (Exh. SCE-1, at 7-31).

The Company asserted that its fuel procurement strategy was intended to ensure low-cost, reliable energy resources for the life of the projected power sales agreements (Exh. SCE-12, at 2). SCE stated that its strategy in developing the TEC fuel supply and transportation arrangements was to obtain a "wraparound" fuel supply, which consisted of an optimal balance between mine mouth costs, transportation costs, ash disposal cost, reliability of the supply, reliability of transportation, environmental impact/compliance, additive costs and equipment compatibility (Exh. SCE-1, at 7-30).

Mr. Montgomery asserted that the selected coal has three very good characteristics -- a low sulfur content, a very high BTU-per-pound ratio, and a very low ash content -- and further

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[274] The Siting Board notes that a signed coal contract has not been submitted in this case. Throughout this document, unless otherwise stated, any reference to the coal contract is intended to mean the draft 20-year coal contract submitted in this case as Exh. EFSC-E-33A.

[275] The GNP-IPD, a national inflation index, reflects overall inflation for all aspects of the economy (Tr. 5, at 123). The GNP-IPD is published monthly by the federal government (id.). SCE assumed a constant GNP-IPD of five percent in its financial calculations (id. at 125).

explained that use of coal with a high BTU content is very efficient and that low ash content minimizes ash disposal concerns (Tr. 5, at 15).[276] SCE reported that it has a commitment from Cyprus to provide coal with a sulfur content of 1.8 percent or less, and it has a performance guarantee from the potential coal supplier to ensure the supply of 1.8 percent coal if Cyprus cannot meet this criteria (Tr. 5, at 12).[277]

SCE provided documentation detailing the coal contract as a 20-year contract with two, five-year extensions, at the option of both parties (Exh. EFSC 33A; Tr. 5, at 98). The draft contract provides for penalties for low BTU content and high ash content, and allows TEC to reject shipments of coal with a sulfur content above 1.8 percent and ash content above 7 percent (Exhs. SCE-12, at 7; EFSC-E-33A).[278] Further, Mr. Montgomery stated that a fixed escalator is tied into the contract, therefore, the risk of escalators diverging from market pricing falls to the potential coal supplier rather than SCE (Tr. 5, at 111). The contract also includes an agreement with JTM, an affiliate of Union Pacific Railroad, to provide ash disposal services at one of two sites outside of Massachusetts (Exh. SCE-12, at 7).

The Company stated it would be obtaining approximately 420,000 tons of coal per year from the potential coal supplier, with the contract maximum being 500,000 tons per year (Exh.

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276 The Company stated that the BTU content of the coal would be 13,200 BTU's per pound (Exh. SCE-12, at 6).

277 The Company provided a letter from the potential coal supplier stating that between the years 1995-2015, Cyprus's coal production would range in average sulfur content from 1.62 percent to 1.68 percent, with the possibility of the figure going as low as 1.55 percent using lower gravity washing (Exh. EFSC-E-35). However, the Company also stated that the coal contract terms are not tied to a particular mine, therefore, the performance guarantee included in the contract could be achieved by using coal from a mine other than Cyprus (id.).

278 Although SCE stated that it would reject coal shipments with a sulfur content above 1.8 percent, the Company does not plan to revise its Air Plans Application, which reflects a 2.0 percent sulfur content (Exh. EFSC-E-33). Mr. Montgomery explained that SCE needs to retain flexibility to respond to unforeseen circumstances such as a force majeure situation, under the coal contract, that would necessitate the use of coal with over 1.8 percent sulfur content (id.; Tr. 5, at 13).

EFSC-E-34). SCE asserted that the potential coal supplier would dedicate sufficient reserves to ensure a reliable, long-term fuel supply for the proposed facility (id.). SCE reported that Cyprus has reserves of approximately 542 million tons, including over 100 million tons of coal with a sulfur content under 1.8 percent (id.).[279] In addition, SCE noted that Cyprus is probably the largest mine on the Conrail system (Tr. 5, at 117). The Company indicated that other mines in the area with similar fuel characteristics also posses extensive reserves which could be used should emergency back-up be needed (Exh. SCE-12, at 6).

The Company stated it intends to provide an on-site, 30-day coal supply, consistent with industry averages (Tr. 5, at 133). Mr. Montgomery indicated that an interruption in fuel supply of 15 days is possible in the industry, but he asserted that a 30-day fuel supply interruption is an extremely unlikely event (id.).

In addition to the back-up coal supply, SCE stated that the TEC facility would be constructed to operate at 40 percent capacity using natural gas as a standby fuel (Exh. SCE-1, at 7-32). The Company indicated that gas also would be used for facility start-up, and that the gas would be supplied to the facility through an existing 10-inch pipeline presently used by TMLP (Tr. 8, at 21).[280] Further, SCE state that Bay State, which presently services the TMLP facility, is extremely interested in providing gas service to the TEC (Exh. EFSC-V-19).

The Company indicated that the final contingency fuel option would be to truck coal from Providence or Brayton Point to the facility (Exh. SCE-12, at 128). SCE stated that this option would be triggered by a prolonged rail strike and would be implemented only as a last resort before shutting down the plant (id.).

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279 SCE stated that the Cyprus reserves include, in addition to the above-mentioned 100 million tons, 200 million tons of under 1.8 percent sulfur coal in the Freeport seam, to be developed in future years (Exh. EFSC-E-34).

280 SCE stated that the existing TMLP gas pipeline met the Company's criteria in that it could supply both the SCE's 40 percent back-up requirements and the TMLP's current and expected future requirements (Tr. 8, at 22).

Conrail was chosen as the proposed rail carrier due to the location of the TEC directly on a Conrail line. The Company asserted that transportation costs would be minimized through the use of a single rail carrier rate (Exh. SCE-1, at 7-31). In addition, based on its analysis of interested fuel suppliers, the Company asserted that use of coal from mines located along the Conrail route would provide the best overall price (id.). SCE stated that Conrail presently has a shortage of good quality, shipper-owned rail cars, and that, therefore, the Company plans to lease up to 200 rapid dump bottom dump cars (id. at 7-32). The Company asserted that owning or leasing a fleet of rail cars would avoid any coal car availability concerns and would allow it to negotiate a service contract with Conrail that includes service guarantees, as well as lower rates (id.; Exh. SCE-12, at 8).

The Company stated that limestone, which will be used to control SO_2 emissions from the CFB, will be purchased in pulverized form and delivered by bulk truck (SCE-3, at III.1-6). The Company stated that eight 25-ton trucks per day, five days a week, are expected for limestone delivery (Exh. EFSC-AER-10). Further, the Company stated that the delivery schedule is to be five days per week, ten hours per day, with two trucks unloading simultaneously (id.).

Mr. Montgomery reported that an economic analysis was performed to determine the least-cost fuel strategy (Exh. SCE-12, at 4). The analysis was comprised of the following components: coal costs at the mine, transportation costs, limestone consumption and costs, plant efficiency, and ash disposal costs (id.). He asserted that the selected coal procurement strategy provides the lowest wraparound price (id.).

SCE has identified a structured fuel acquisition process that exhibits several important advantages for the proposed project. First, SCE has a draft contract for a long-term dedicated coal commitment including supply, transportation and ash disposition. Second, the Company has a detailed back-up supply plan, the key components being a 30-day on-site coal supply and the ability to switch to natural gas for limited operation. Third, the draft contract contains provisions to allow for the refusal of coal with higher-than-agreed-upon sulfur and/or ash content, and a lower-than-agreed-upon BTU content. Fourth, the coal contract incorporates price escalators based on a standardized inflation indicator, ensuring that the project's fuel supplies will remain reasonably priced over time. However, the Company has not provided a final executed coal contract or transportation contract. If the final coal contract contains all of the significant provisions as those in the draft coal contract, SCE will be able to establish that its fuel acquisition strategy reasonably ensures a low-cost, reliable coal supply. Therefore, the Siting Board requires SCE to provide the Siting Board with a signed copy of a coal contract between SCE and a coal supplier and any other contract that may be necessary for transportation of the coal.

Accordingly, the Siting Board finds that based on compliance with the above condition that SCE provide the Siting Board with a signed coal contract and transportation contract that is the same or similar with regard to all significant provisions as those in the draft coal contract, SCE will have established that its fuel acquisition strategy reasonably ensures a low-cost, reliable source of energy over the term of its projected and likely power sales agreements.

The Siting Board has found that SCE has established that (1) upon compliance with the condition relative to providing a copy of a signed O&M contract, the proposed project is likely to be operated and maintained in a manner consistent with reliable performance over the likely term of the project PPAs, and (2) upon compliance with the condition relative to providing a copy of a signed coal contract and transportation contract, its fuel acquisition strategy reasonably ensures a low-cost, reliable source of energy over the likely term of the project PPAs. Accordingly, the Siting Board finds that, upon compliance with the aforementioned conditions, SCE will have established that its proposed project meets the Siting Board's second test of viability.

4. Findings and Conclusions on Project Viability

In Section II.C, above, the Siting Board has made the following subsidiary findings:

- that upon compliance with the condition in section II.C.2.a, above, regarding provision of a steam sales agreement and the condition in Section II.A.5.c, above, regarding provision of PPA's, SCE will have established that its proposed project is likely to be financiable;

- that upon compliance with the conditions in Section II.C.2.b, above, regarding provision of an EPC contract and an interconnection agreement, SCE will have established that its proposed project is likely to be constructed within the applicable time frames and be capable of meeting performance objectives;
- that, upon compliance with the conditions in Sections II.A.5.c and II.C.2, above, SCE will have established that its proposed project meets the Siting Board's first test of viability;
- that upon compliance with the condition in Section II.C.3.a, above, regarding provision of an O&M contract, SCE will have established that the proposed project is likely to be operated and maintained in a manner consistent with reliable performance over the life of projected and likely power sales agreements;
- that upon compliance with the condition in Section II.C.3.b, above, regarding provision of a signed coal contract and transportation contract that is the same or similar with regard to all significant provisions as those in the draft coal contract, SCE will have established that its fuel acquisition strategy reasonably ensures a low-cost, reliable source of energy over the term of its projected and likely power sales agreements;
- that, upon compliance with the conditions in Section II.C.3., above, SCE will have established that its proposed project meets the Siting Board's second test of viability.

III. ANALYSIS OF THE PROPOSED FACILITIES

The Siting Board has a statutory mandate to implement the policies of G.L. c. 164, §§ 69H-69Q to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. G.L. c. 164, § 69H. 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. Cabot Power Decision, 2 DOMSB at 371; Altresco Lynn Decision, 2 DOMSB at 171; 1993 BECo Decision, 1 DOMSB at 35.

A. Description of the Proposed Facilities at the Primary and Alternative Sites

As noted above, SCE proposes to construct a 169 MW bulk generating facility with a nominal output of 150 MW in the City of Taunton (Exh. SCE-3, at III.1-15). The TEC, as proposed, would operate as a cogenerator, supplying steam to a proposed CO_2 production plant to be constructed on the chosen facility site (Exh. SCE-1, at 1-1).

The primary site for the proposed facility would be located within an approximately 100-acre parcel of land of the TMLP complex and bordered, generally, by the Taunton River to the east; Railroad Avenue to the south; Somerset Avenue (Route 138) to the west; and the existing TMLP access road to the north (Exh. SCE-3, at III.2-1). The alternative site would be located within a 250-acre parcel of Commonwealth-owned land bordered by the Miles Standish Industrial Park to the north, the Dever State School to the east and an active Conrail line to the southwest (Exh. SCE-1, at 8-27, 8-28).

The major components of the proposed project at both sites consist of: (1) a boiler building housing a single-turbine-generator; (2) an exhaust gas baghouse; (3) lime and ash storage silos; (4) an emission stack approximately 397 feet in height; (5) a turbine generator building; (6) an administrative and warehouse building; (7) an enclosed coal storage building and coal crusher building; (8) a coal unloading building and train break-down yard; (9) a cooling tower; (10) storage tanks for condensate, wastewater, and ammonia; (11) a wastewater treatment plant; and (12) a CO_2 production plant (id. SCE-3, at III.1-4, 1-5, 1-6, 1-14, 1-18). At the primary site, new overhead transmission lines would be constructed to connect the proposed facility to the existing TMLP switchyard, where two existing transmission lines originate that connect to the regional 115 kV transmission system (Exhs. SCE-3, at III.1-23; EFSC-E-71). At the alternative site, a new two-mile overhead transmission line would be constructed along the Conrail line to connect the proposed facility to existing TMLP transmission lines that in turn extend to the TMLP switchyard at the primary site (Exh. SCE-1, at 9-12; EFSC-E-71, att.).

The primary fuel for the proposed facility at both sites would be eastern bituminous coal with natural gas to be used for start-up and stabilizing combustion (id. at III.1-1, 1-2). A thirty-day supply of coal and a five-day supply of limestone would be stored on the TEC site in enclosed buildings (id. at III.1-4, 1-6). The coal needed for the TEC would be transported to Taunton by rail along existing ROW in unit trains, 80 rail cars in length (id. at III.1-2). A 3.1-mile rail spur would be restored by Conrail along existing ROW owned by TMLP to allow coal delivery to the primary site, and a new rail loop would be constructed to provide rail access onto the alternative site (Exhs. SCE-3, at VI.10-1: EFSC-S-7). The limestone would be delivered in eight 25-ton trucks per day, five days per week (Exh. EFSB-AER-10).

The source of cooling tower makeup water would be from the Taunton River and municipal water would be used for boiler water makeup, miscellaneous uses and fire protection (id. at II.1-16, III.1-19). At the alternative site, water supply and wastewater lines three to six miles in length would be required for cooling water purposes (Exhs. SCE-1, at 9-11; SCE-15, Att. R-5, at 4).

B. Site Selection Process

1. Standard of Review

In order to determine whether a facility proponent has shown that its proposed facilities siting plans are superior to alternatives, the Siting Board requires a facility proponent to demonstrate that it examined a reasonable range of practical facility siting alternatives. Cabot Power Decision, 2 DOMSB at 373; Altresco Lynn Decision, 2 DOMSB at 164; NEA Decision, 16 DOMSC at 381-409. In order to determine that a facility proponent has considered a reasonable range of practical alternatives, the Siting Board requires the proponent to meet a two-pronged test. First, the facility proponent must establish that it developed and applied a reasonable set of criteria for identifying and evaluating alternatives in a manner which ensures that it has not overlooked or eliminated any alternatives which are clearly superior to the proposal. Cabot Power Decision, 2 DOMSB at 373; Altresco Lynn Decision, 2 DOMSB at 164; Berkshire Gas Company (Phase II), 20 DOMSC at 109 (1990) ("1990 Berkshire Decision"). Second, the facility proponent must establish that it identified at least two noticed sites or routes with some measure of geographic diversity.[281] Cabot Power Decision, 2 DOMSB at 393; Altresco Lynn Decision, 2 DOMSB at 144 through 145; NEA Decision, 16 DOMSC at 381 through 409. In past decisions, the Siting Board has not required a noticed alternative site in cases involving proposals to construct cogeneration facilities if the cogeneration proponent (1) had a steam sales agreement with existing steam purchaser(s) sufficient to qualify it for QF status, and (2) had a proposed site fully within the property boundaries of the principal steam host. Cabot Power Decision, 2 DOMSB at 373-374; Altresco Lynn Decision, 2 DOMSB at 165; MASSPOWER Decision, 20 DOMSC at 328.

However, 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

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[281] When a facility proposal is submitted to the Siting Board, the petitioner is required to present (1) its preferred facility site or route, and (2) at least one alternative site or route. These sites and routes often are described as the "noticed" alternatives because 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.

requirements. See also, 980 C.M.R. 9.00. In the present case, the proposed TEC site is located adjacent to, but not within the boundaries of the Massachusetts coastal zone, and the noticed alternative site also is located outside such boundaries (Exh. SCE-3, at VI.6-7; EFSC-E-72).[282]

In the sections below, the Siting Board reviews the Company's site selection process, including SCE's development and application of siting criteria as part of its site selection process.

2. Development of Siting Criteria

a. Description

SCE asserted that it has presented an acceptable site selection process to the Siting Board, including the development of acceptable criteria for identifying and evaluating alternatives (SCE Brief at 170). SCE indicated that it developed four sets of criteria for use in an iterative decision process, including criteria for a host selection stage and three stages of site selection (Exhs. SCE-1, at 8-2; EFSC-S-10).

The Company stated that the following criteria were developed to identify potential cogeneration development opportunities in Massachusetts: (1) sufficient regional electrical generation demand; (2) sufficient area electrical generation demand; (3) identification of a suitable steam host; (4) adequate size of site, and/or the probability of procurement or control

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282 At the primary site, the TEC would draw water from, and discharge process water to, the Taunton River, a mapped coastal resource (Exhs. SCE-3, at IV. 2-18; EFSC-E-72). The MCZM Office determined, therefore, that a federal consistency review, conducted by the MCZM Office, is required for the issuance of a NPDES permit for process wastewater and stormwater (id.). At the alternative site, the TEC might use the same intake/discharge location as at the primary site or alternative intake/discharge locations further upstream on the Taunton River (see Section III.C.2.a.iii, below). Based on the record, it is unclear whether all possible intake/discharge locations for the TEC at the alternative site are located within a mapped coastal resource.

of adequate land area; (5) environmental compatibility with respect to air, water, wetlands, sensitive areas, transmission access, land use, and transportation access; and (6) probability of community acceptance (Exh. EFSC-S-10). SCE asserted that it employed a systematic site selection approach that ultimately resulted in the selection of the TMLP service area as the general location of the project (id.).[283]

The Company stated that it was SCE's position that the Siting Board, in its review process, should consider TMLP (and its service territory) as the project host analogous to the role of an established steam host (Exh. EFSC-S-3). SCE asserted that in previous cases, the Siting Council has allowed an existing steam host, once selected, to serve as a constraint on the second stage of the site selection process, with proximity of the steam host becoming an overriding siting criterion (id.). The Company stated that siting the TEC within the TMLP service territory was analogous to siting a cogeneration facility near its existing steam host, if any, because: (1) at the primary site, TMLP would be providing land both for the proposed TEC and a steam user, specifically a CO_2 plant, as necessary to qualify as a QF;[284] (2) TMLP would be purchasing power from TEC, similar to a steam user purchasing steam; (3) at the primary site, the presence of the existing TMLP generating facilities would provide common-use opportunities for such facility elements as the switchyard and the cooling water intake and treatment system; (4) given TMLP's established presence in the area, the host

283 The Siting Board notes that at this point in the site selection process, the present SCE development team consisting of CSC, CSI and Bechtel was not in existence. All site selection activity concerning potential steam hosts was conducted solely by CSC.

284 SCE indicated that its lease arrangement with TMLP for the primary site also would serve financial and land use objectives of TMLP (Exh. EFSC-S-3b). Specifically, SCE indicated that, as a result of SCE's lease agreement with TMLP (1) SCE would pay TMLP $1,000,000 per year once the TEC is on-line, and (2) the TEC would utilize TMLP-owned land with limited value for alternative uses (Tr. 6, at 139 through 141). Notwithstanding the expectation that such TMLP objectives would be served, SCE asserted that the lease agreement is distinct from any energy supply planning or resource acquisition decision making by TMLP, and thus is not subject to Siting Board or Department review as part of TMLP's resource acquisition process (Exh. EFSC-S-3b).

relationship with TMLP would provide advantages to the TEC with respect to permitting and community acceptance; and (5) given TMLP's existing generating base in the area, the host relationship with TMLP would provide joint marketing options for the proposed TEC power output (Exh. EFSC-S-3).

The Company stated that it also developed three sets of decision criteria to select a site in the vicinity of the project host, including search criteria, screening criteria, and evaluation criteria (Exh. SCE-1, at 8-2). The Company indicated that it used the search criteria to identify the field of potential alternatives, then used the screening criteria to narrow the field to the two best alternatives, and finally used evaluation criteria to compare the two sites and determine which site was superior on the basis of environmental impacts (id. at 8-3).

SCE stated that it used increasingly inclusive and detailed criteria for its three site-selection iterations following selection of the project host (id. at 8-2 through 8-22). SCE stated that the following search criteria were absolutely necessary for an initial identification of possible CFB plant sites and should govern the initial site search: site compatibility;[285] availability of sufficient upland area; and potential for rail access (id. at 8-6). For the next stage -- the screening of sites -- the Company added two additional criteria: availability of cooling water and transmission line access (id. at 8-7).

For the final stage -- the evaluation of sites -- SCE presented the evaluation criteria, which encompassed all of the search and screening criteria along with additional environmental decision criteria (id. at 8-10). Specifically, SCE identified the following evaluation criteria and sub-criteria: (1) site compatibility: (a) current site use; (b) population density; (c) neighboring land use; and (d) proximity to sensitive receptors; (2) water availability: (a) proximity to

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285 The Company stated that, to be compatible, it is important for a facility site to be of sufficient size to accommodate the facility while maintaining a buffer zone from residential areas and other sensitive receptors, but that a buffer zone has less importance in an industrial area (Exh. SCE-1, at 8-6). The Company further stated that, in considering whether a site or its surrounding area is industrial or residential in nature, it focused on the existing land use rather than how the land was zoned (Tr. 1, at 111 through 113).

available water supply; (b) impacts of providing water supply; and (c) potential for wastewater discharge; (3) rail access: (a) proximity of rail line to site; (b) surrounding land use; (c) operation impacts; and (d) socioeconomic benefits of rail improvements; (4) transmission line access: (a) proximity of 115 kV line to site; (b) need for transmission ROW expansion; and (c) proximity to sensitive receptors; (5) wetlands: (a) proximity; (b) extent of alteration/impacts; and c) quality of wetland; (6) air quality: (a) ambient conditions and (b) urban vs. rural modeling coefficient; (7) groundwater/ floodplain: (a) proximity to aquifer; (b) proximity to existing drinking wells; and (c) proximity to floodplain; (8) steam host potential: (a) proximity, and (b) impacts/benefits; (9) community socio-economic factors: (a) tax base/employment, and (b) community support; (10) ecology, species/habitat; (11) transportation access: (a) highway and (b) traffic disruption due to operations; and (12) cultural resources: (a) historic and (b) archaeological (id. at 8-20 through 8-22).

The Company developed a weighting process for the evaluation criteria, whereby search criteria were assigned the highest weight of 15 points, screening criteria were assigned a weight of ten points, and the remaining evaluation criteria were weighted at five points (id. at 8-11 through 8-13). SCE stated that the criteria were designated critical, very important and important in terms of assigning the weights (id.). The Company noted that the evaluation criteria were not used throughout the site selection process in a rigid manner, but that judgment was involved in studying the initial universe of sites and in implementing the associated screening process (Tr. 1, at 127). In addition, SCE stated that weighting involves judging the relative importance of the various criteria, and that ultimately the test of a weighting/ranking system is whether a selection makes sense and holds up under further consideration (Exhs. EFSC-S-5; EFSC-S-6).

b. Analysis

In previous decisions regarding generating facilities, the Siting Board has reviewed criteria such as those developed by SCE for use in an iterative site selection process, beginning with a broad identification and screening of sites and narrowing to a more detailed evaluation of a few best sites. 1993 BECo Decision, 1 DOMSB at 43-50; Enron Decision, 23 DOMSC at 128-130; Altresco-Pittsfield Decision, 17 DOMSC at 391-392. In a number of such cases involving cogeneration facilities that would provide steam for existing steam hosts, the Siting Board has reviewed criteria that include, as a first iteration, factors related to the identification and evaluation of steam hosts. Altresco Lynn Decision, 2 DOMSB at 167; EEC Decision, 22 DOMSC at 318; Altresco-Pittsfield Decision, 17 DOMSC at 391.

The record indicates that SCE's criteria for the identification and evaluation of project hosts are generally similar to steam host selection criteria accepted in previous reviews. Id. As one difference, however, SCE identified the criteria of transmission access and transportation access as environmental compatibility issues in host selection, while in previous cogeneration facility reviews such access criteria were set forth as fundamental viability issues. Id. Given that transmission and transportation access directly affect cost and reliability concerns as well, SCE's reason for singling these issues out as environmental concerns are unclear. Nonetheless, SCE has developed overall a reasonable set of host selection criteria.

In regard to it's development of site selection criteria for identifying and evaluating possible sites, the Company has included and considered an encompassing array of criteria in a three phase process. However, the Siting Board questions the omission of zoning as a siting criteria, as zoning has been used as an indicator in all but one of the Siting Board's previous NUG facility cases. Altresco Lynn Decision, 2 DOMSB at 167; Enron Decision, 23 DOMSC at 126; EEC Decision, 22 DOMSC at 318; West Lynn Decision, 22 DOMSC at 81; MASSPOWER Decision, 20 DOMSC at 377; Altresco-Pittsfield Decision, 17 DOMSC at 392;

NEA Decision, 16 DOMSC at 386.[286] In the present case, the absence of the use of industrial zoning as a component of the site compatibility criteria is notable in that the TMLP site is not located in an industrial zone.

Notwithstanding the omission of the zoning designation, the Siting Board notes that in previous decisions it has accepted criteria such as those developed by SCE, and that the criteria are thus consistent with the site selection criteria which the Board has found to be appropriate for cogeneration facilities. Cabot Power Decision, 2 DOMSB at 380-381; Altresco Lynn Decision, 2 DOMSB at 169; Enron Decision, 23 DOMSC at 127; MASSPOWER Decision, 20 DOMSC at 378-379.

With respect to weighting, SCE assigned varying weights to the site selection criteria based on their initial introduction as either search, screening, or final evaluation criteria. By following a comprehensive weighting and scoring system, SCE has addressed the Siting Board concerns raised in previous decisions regarding the absence of weights for site selection criteria. 1993 BECo Decision, 1 DOMSB at 57-58; Enron Decision, 23 DOMSC at 127; MASSPOWER Decision, 20 DOMSC at 378-379.

Although SCE's iterative criteria and its scoring/weighting approach within each iteration are generally appropriate, SCE's position that the sequential narrowing of the geographic range of sites would be analogous for a steam host and an electric utility host raises concerns. The Siting Council previously has recognized that applicants reasonably narrowed site selection to within a few miles of a steam host, after first-iteration steam host selection, consistent with identified steam host proximity criteria reflecting engineering constraints for transporting steam. Altresco-Pittsfield Decision, 17 DOMSC at 392-394. However, there is no basis to assume that any similar constraints for transporting power occur at comparable distances. With the exception of peaking power sources, limitation of generation to a utility's own territory is neither necessary, nor generally practiced in New England, based on

286 In the one exception, Cabot Power Decision, the applicant identified steam host proximity criteria which, in effect, limited possible sites to industrial areas. 2 DOMSB at 371, 376-378, 380.

physical/engineering or any other considerations. We note that none of the reasons put forth by the Company in support of its position that TMLP was analogous to a steam host represent such physical or engineering constraints.[287]

The Siting Board, therefore, finds that SCE failed to identify physical/engineering constraints that warrant limiting possible siting of its proposed generating facility to a host utility territory, analogous to the limitation of possible siting of a proposed cogeneration facility to the vicinity of a selected existing steam host.

The Siting Board notes that SCE indicated its TMLP land lease arrangement also would serve TMLP's financial and land use objectives, by providing TMLP with rent payments for currently unused land owned by TMLP.[288] Thus, to fully address SCE's position concerning the scope of its site selection process, the Siting Board also considers whether the lease arrangement is a business consideration that warrants weight as justification for SCE's limitation to the TMLP service territory.

In the Cabot Power Decision, the Siting Board accepted a beforehand limitation to the thermal host based on business considerations stemming from the corporate ties of the facility developer and the thermal host and the nature of the host's thermal requirement. 2 DOMSB at 379-380 While noting that common host-developer identity, taken alone, generally would not justify such a limitation, the Siting Board concluded in that review that the selected thermal host provided a cogeneration design advantage in that it actually would require hot water rather than steam for its thermal purposes -- thereby increasing overall plant efficiency -- and the selected host provided essentially on-site access to a firm fuel supply at the desired cost, attributes not present in any previous Siting Board reviews of cogeneration facilities. Id. at 380.

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[287] We also note, however, that some of the advantages identified by SCE may be wholly appropriate for consideration in comparing sites.

[288] SCE also asserted that the lease is not a TMLP supply planning arrangement, and therefore should not be subject to supply plan or supply contract review by either the Department or Siting Board. As all such reviews are the responsibility of the Department, the Siting Board does not address SCE's assertion.

Here, a beforehand limitation to TMLP's territory would encourage, although not ensure, selection of a site that, in SCE's view, would provide an overriding benefit to TMLP in the form of land lease payments and use of an otherwise marginally usable site. However, SCE has no common identity with TMLP comparable to the common-identity between the applicant and the steam host in the Cabot Power Decision. Further, SCE has not demonstrated on this record that the primary site, which has separate frontage on Railroad Avenue, poses compelling land use advantages that the Siting Board could consider to be an energy-related benefit justifying limitation of the site selection process. In fact, SCE's contention that the land lease arrangement is not appropriately subject to supply plan review brings into question whether it has status as an energy-related benefit, raising uncertainty as to any relevance of the asserted advantages of the lease arrangement for the Siting Board's site selection review. Accordingly, the Siting Board finds that SCE has failed to identify business considerations that warrant limiting possible siting of its proposed facility to a host utility service territory.

In previously clarifying its standard of review for cogeneration facilities proposed to serve existing steam hosts, the Siting Council has affirmed that a comprehensive site selection process is the best way to ensure that a reasonable range of practical siting alternatives have been considered. See, MASSPOWER Decision, 20 DOMSC at 381. The Siting Council stated that, regardless of whether a noticed alternative site is required in a particular case, it will review an applicant's site selection process to ensure that clearly superior facility sites have not been overlooked or eliminated. Id. at 382.

Here, the limitation of possible sites to the TMLP territory -- Taunton and four surrounding municipalities -- raises questions as to whether clearly superior sites may have been overlooked outside that territory. While such a geographic scope may well allow identification of sufficient possible sites to afford a range of impact levels for many of the environmental factors considered, there is the potential for limited geographic scope to unduly constrain siting opportunities with respect to some factors. However, in order to determine whether such is the case here, the Siting Board must review SCE's application of siting criteria, including SCE's identification and evaluation of sites.

Accordingly, based on the foregoing, the Siting Board finds that SCE has developed a generally reasonable set of criteria for identifying and evaluating alternative sites, but has failed to justify the incorporation of a narrow geographic scope limitation, based on a host utility service territory, as part of its identification framework.[289]

3. Application of Siting Criteria

a. Description

SCE stated that it initially targeted the REMVEC area, particularly Southeastern Massachusetts, as the primary project area due to the Company's knowledge of that area's need for additional generating capacity and the strong probability that a suitable steam host would be found in that area (Exh. EFSC-S-10). The Company further stated that it consistently had focused on developing a cogeneration facility due to the regulatory complexities of developing and owning an independent power project (Exh. EFSC-S-2).

SCE's witness, Mr. Roberts, stated that CSC developed a range of potential steam hosts and sites during 1988-1989, prior to bidding on the TMLP RFP (Tr. 6, at 162).[290] The following potential sites were identified: Ocean Spray Cranberries, Inc., Plymouth Industrial Park, Cordage Park, Braintree Electric Light Plant, and Miles Standish Industrial Park (Exh. EFSC-S-10).[291]

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289 We recognize that an applicant may place limits on the site selection process for various reasons. However, an applicant must demonstrate that such limits are not inconsistent with our standard that a clearly superior site has not been overlooked or eliminated.

290 SCE stated that it utilized electrical distribution maps, gas transmission maps, rail line maps, marine charts, business journals, newsletters, and networking to determine five potential host sites (Exh. EFSC-S-10).

291 The Siting Board notes that the identification of the fives host sites was not limited to identified host users of energy. Of the five sites, one listed an established industrial steam host, one involved an electric utility as the host, and the remaining three were industrial park sites for which a specific host user of energy had not been identified. As such, SCE's identification of potential hosts incorporated a broader category than a

(continued…)

Mr. Roberts indicated that before CSC could complete its analysis of the above options, the TMLP RFP surfaced as an option, and CSC determined that it met all of the stated host selection criteria and was a superior opportunity (id.; Tr. 6, at 160).[292] SCE indicated that CSC joined efforts with CSI in order to pursue the TMLP RFP option (Exh. EFSC-S-10). SCE added that, after joining efforts, the two-partner team also had the option of pursuing the Neptune Project, a coal-fired cogeneration project being developed by CSI at an existing steam host site in Providence, Rhode Island (Exh. EFSC-S-10).[293]

With respect to the selection of an appropriate site for the TEC, SCE limited the geographic area to the TMLP service area, which consists of Taunton and parts of North Dighton, Raynham, Lakeville and Berkley (Exh. SCE-1, at 8-4).[294] The Company utilized United States Geological Survey ("USGS") topographic maps to identify existing rail lines, old railroad grades, existing power transmission lines, and all apparent upland parcels of approximately 20 acres or larger (id. at 8-19).[295] SCE also contacted the Taunton Industrial

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[291](…continued)
typical identification process, in which a cogenerator developer seeks an existing steam host.

[292] The Company stated that its criteria requiring identification of a suitable steam host was satisfied by the ability to construct a CO_2 plant on the primary site for the TMLP RFP project (Exh. EFSC-S-10). SCE also stated that it considered TMLP to be analogous to a steam host (Tr. 6, at 163) (see Section III.B.2, above).

[293] Mr. Roberts testified that the Neptune project was later cancelled after the discovery of a hazardous waste problem at the site (Tr. 6, at 163 through 164).

[294] SCE stated that the formal alternative site selection analysis was undertaken after the Company was informed by HMM that the process would have to be documented to comply with the EFSB standard that a superior site had not be overlooked (Exh. EFSC-S-11). However, the Company stated that it did screen sites in the TMLP service area prior to the submittal of the EFSB petition, and further, that Mr. Roberts had screened other possible sites in TMLP's service area prior to the submission of the first TMLP RFP (id.).

[295] SCE stated that it initially thought that the Taunton River could possibly allow use of
(continued…)

Commission, and the City of Taunton Planning and Engineering Departments concerning possible sites (Tr. 1, at 119; Tr. 3, at 98). However, Mr. Mygatt stated that the Company did not contact officials from other surrounding communities in the process of identifying sites (Tr. 3, at 98).

SCE identified thirteen sites and subsequently eliminated seven of the sites by applying the search criteria (id.; Exh SCE-1, at 8-10).[296] SCE then applied the screening criteria to the remaining six sites, consisting of: (1) Miles Standish Industrial Park Expansion Area in Taunton; (2) Route 140 Industrial Park in Taunton; (3) West Water Street in Taunton; (4) an undeveloped wooded site in North Raynham; (5) East Taunton Industrial Area in Taunton; and (6) TMLP Cleary-Flood Station site in Taunton (Exh. SCE-1, at 8-27). The Company applied a scoring system to the six sites, whereby +1 indicated positive attributes for particular criteria, 0 indicated minimum suitability, and -1 indicated that the site was poorly suited (id. at 8-10). The screening process narrowed the field to two sites, the primary site, near the TMLP Cleary-Flood station, and the alternative site, adjacent to the Miles Standish Industrial Park (id.).[297,298]

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[295](…continued)
barge transportation for the primary site, but that further studies indicated barge transportation to that location was neither environmentally nor economically feasible (Exh. EFSC-S-10).

[296] The seven sites, consisting of two sites in Berkley, three sites in Lakeville, and two sites in Taunton, were eliminated based on more detailed evaluation of wetlands conflicts, residential conflicts and rail access difficulties (Exh. SCE-1, at 8-23, 8-26; Tr. 3, at 98).

[297] In evaluating the six sites based on its five screening criteria, SCE assigned ten +1 scores, nine zero scores, and 11 -1 scores (Exh. SCE-1, at 8-38). Of the selected sites, the primary sites scored +1 on site compatibility, wetlands impacts, water supply access and transmission access, and the alternative site scored +1 on wetland impacts and rail access; of the eliminated sites, one site -- the West Water Street site in the industrialized Weir section of Taunton -- scored +1 on site compatibility, while two sites scored +1 on water supply access and one site scored +1 on wetlands impact (id. at 8-38). Neither of the selected sites scored -1 on any criteria; however, for each of the criteria, two or more of the eliminated sites scored -1, including two sites for site

(continued…)

SCE applied the evaluation criteria to the two sites utilizing a scoring matrix based on the evaluation criteria and sub-criteria (id. at 8-12). Each site was ranked by assigning point values to the sub-criteria, either one, two or three, whereby three was the maximum suitability (id. at 8-18). The primary site ranked higher for the categories of site compatibility, water availability, transmission line access, and socioeconomic considerations; the alternative site ranked higher for rail access, steam host potential, and transportation access; and both sites were scored equally for wetlands, air quality, groundwater/floodplain, ecological considerations, and cultural resources (id. at 9-11 through 9-13).

The Company averaged the sub-criteria scores to determine the score for each of the evaluation criteria, then the evaluation criteria were weighted as described in the previous section. This analysis yielded a score of 88 for the primary site and a score of 78 for the alternative site (id. at 8-18, 9-10). Based on this analysis, SCE asserted that the primary site was the preferred site on the basis of environmental impacts (id. at 9-14).

b. Positions of the Intervenors

Mr. Graban asserted that the primary site had already been determined in October of 1989 by TMLP, by virtue of the RFP solicitation and award (Graban Brief at 3-2). He stated that at that time, TMLP indicated that it hoped to have a 150 MW plant located on the Cleary-Flood station site on Somerset Avenue (id.). Mr. Graban stated that public input to the site selection process did not occur and that the selection of the alternative site appeared to be an afterthought by the Company due to Siting Board filing requirements (id.).

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[297](…continued)
compatibility, three sites for wetlands impacts, two sites for rail access, two sites for water supply access, and two sites for transmission access (id.).

[298] In scoring sites based on compatibility, the Company assigned scores of +1 for the two sites with the least land availability -- the primary site and the West Water Street site -- citing existing industrial character; however, the Company assigned -1 scores to two other larger sites -- a 30-acre industrial area parcel and an over 300-acre undeveloped area parcel -- citing a school three-quarters of a mile away and neighboring residential land use, respectively (Exh. SCE-1, at 8-31 through 8-43).

c. Analysis

The Siting Board notes that the Company identified a number of cogeneration options at established steam user or industrial park sites, having developed steam host selection criteria at an early stage in the process in its search for project opportunities. Further, in selecting the TMLP RFP option as the best development opportunity, albeit absent any existing steam host, SCE did apply its steam host selection criteria to the TMLP RFP option and concluded that all the criteria were met or exceeded by the project. However, in considering alternative project hosts, SCE did not complete an analysis of competing steam hosts, and thus selected the TMLP RFP option without clearly establishing the reasons for rejecting the alternative project host options. In the future, due to the fact that the choice of a steam host often substantially limits the range of siting options, and to ensure that a cogeneration project meets the Siting Board's standard that necessary energy supplies be provided at the least cost, with a minimum impact on the environment, facility applicants will be expected to undertake a complete analysis of competing identified project host options.

The Siting Board notes that, as in the Siting Council's earlier NEA Decision, the proposed facility in this review would include a "host" steam user facility, the CO_2 production plant, that is yet to be constructed. 16 DOMSC at 367. However, as discussed in Section III.B.2.b., above, SCE limited its site selection process based on a host relationship with TMLP, and as a result focused on sites in the TMLP service territory. The Siting Board further addresses below the possible effect of SCE's limitation to the TMLP service territory in SCE's application of its site selection criteria.

The record shows that, in its selection and evaluation of specific sites, SCE first applied its search criteria to 13 preliminary alternatives, then applied its screening criteria to six sites, and ultimately compared the primary and alternative sites based on detailed evaluation criteria. In identifying sites, SCE focused on utilizing USGS maps of the TMLP service area and conferring with City of Taunton Officials. SCE utilized a systematic scoring approach to quantitatively compare sites at the screening stage, and a comprehensive scoring and weighting system to quantitatively evaluate the primary and alternative sites.

With respect to compatibility, although SCE's criteria at all stages separate out a number of component factors, including site size and extent of buffer, as well as developmental character in the surrounding area, SCE's assignment of compatibility scores at both the screening and final evaluation stages raises concerns. At the screening stage, SCE assigned a -1 score to an over 300-acre site -- a site with apparently ample on-site buffer potential -- citing the prevailing residential and rural character of the site vicinity. In contrast, at both the screening and final evaluation stages, SCE rated the primary site equal to or above competing sites, citing the industrial character of the area and claiming an ability to provide adequate buffer. As discussed in Section III.C.2.a.iv., below, however, the Siting Board questions SCE's assessment of the extent of existing industrial character at the active primary site, as well as SCE's position that the proposed TEC would be adequately buffered from the nearest residences.

Despite the above concerns with SCE's scoring of sites based on compatibility, the Siting Board notes that adjustments to the compatibility and overall scores would not change the ranking of the selected sites at either the screening or final evaluation stages. Thus, within the geographic limits set by SCE, SCE applied its criteria to identify and evaluate sites in the TMLP service territory in a manner that ensures it did not overlook or eliminate any clearly superior sites.

With respect to the geographic scope of SCE's site selection process, we note that with respect to one criteria, transportation and delivery of coal, SCE's identified sites reflected differences in the degree of local accessibility to existing rail lines. However, given SCE's limitation to the TMLP service territory, all the identified sites required the use of secondary rail lines between Framingham and Taunton, with associated rail traffic impacts at grade crossings (see Section III.B.2., above, and Section III.C.2.a.vii., below). The limitation precluded the possibility that any alternative sites to the west and north of the Taunton area, which would reduce or avoid use of such secondary rail lines and associated grade crossing impacts, would be identified and evaluated. Further, although SCE claims that the option of barge delivery was a theoretical possibility when it first focused on the TMLP service territory, and the primary site in particular, the option of barge delivery was quickly discarded based on likely dredging requirements in the Taunton River to allow access to the primary site. SCE's limitation to the TMLP territory eliminated the possibility that any alternative sites outside of the TMLP territory where barge delivery may have been more feasible would be identified and evaluated. Thus, SCE's limitation of the site selection process to the TMLP territory essentially precluded the option of a site that would significantly reduce the use of secondary rail lines, and largely precluded the option of a site that would allow substitution of direct barge transport for rail transport.

The Siting Board further notes, however, that the six sites in SCE's quantitative screening analysis, and to a large degree the primary and alternative sites, reflect a significant range of choice with respect to the other criteria applied by SCE. Specifically, the sites provided choices with respect to site size, developmental character, and natural resource characteristics, as well as attributes related to electric transmission and water access. Thus, the possibility that SCE's limitation of the site selection process to the TMLP territory might have resulted in clearly superior sites being overlooked generally is not borne out by the record.

Accordingly, the Siting Board finds that, with the exception of the application of criteria relating to rail transport, SCE has appropriately applied a reasonable set of criteria for identifying and evaluating alternatives in a manner that ensures that it has not overlooked or eliminated any clearly superior sites.

4. Geographic Diversity

In this section, the Siting Board considers the second prong of the practicality test -- whether SCE's site selection process included consideration of site alternatives with some measure of geographic diversity. The Company asserted that the siting process has resulted in the identification of two sites which are geographically diverse (Exh. SCE-1, at 8-44). SCE stated that the sites are geographically separate, located approximately 5.25 miles apart (id.)

Mr. Mygatt further indicated that SCE wanted sites that would provide diversity, so that the Siting Council could conduct a useful comparison (Tr. 3, at 106 through 107).

The Siting Board requires that an applicant must provide at least one noticed alternative with some measure of geographic diversity. 1993 BECo Decision, 1 DOMSB at 64; Berkshire Gas Company ("1991 Berkshire Decision"), 23 DOMSC 294, 332 (1991); Enron Decision, 23 DOMSC at 130; 1990 Berkshire Decision, 20 DOMSC at 181-182.[299] The Siting Board notes that there is no minimum distance that is sufficient to establish geographic diversity in any given case. The Siting Council previously determined that two sites in the same town can provide adequate geographic diversity for generating facilities review. Enron Decision, 23 DOMSC at 130; NEA Decision, 16 DOMSC at 385-388. Further, in a transmission line case, the Siting council stated that simple quantitative diversity thresholds were not appropriate for evaluating geographic diversity. New England Power Company ("1991 NEPCo Decision"), 21 DOMSC 325, 393 (1991).

Here, SCE provided two sites located 5.25 miles apart in the same city. Nonetheless, as discussed above, SCE's site comparisons show that the two sites and their surroundings possess different characteristics with respect to such factors as site size, natural resource conditions, developmental character, and accessibility.

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

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299 As noted in Section III.B.1, above, in the MASSPOWER Decision, the Siting Council set forth a standard that, if met, would exempt certain cogeneration facilities from the noticed alternative requirement (20 DOMSC at 382). However, SCE does not meet the requirements of the standard; specifically SCE has not proposed to sell steam to an existing steam user with sufficient steam demand to qualify the project as a QF.

5. Findings and Conclusions on Site Selection Process

In Sections III.B.2,3 & 4, above, the Siting Board has made the following subsidiary findings:

- that SCE failed to identify physical/engineering constraints that warrant limiting possible siting of its proposed generating facility to a host utility territory, analogous to the limitation of possible siting of a proposed cogeneration facility to the vicinity of a selected existing steam host;
- that SCE has failed to identify business considerations that warrant limiting possible siting of its proposed facility to a host utility service territory;
- that SCE has developed a generally reasonable set of criteria for identifying and evaluating alternative sites, but has failed to justify the incorporation of a narrow geographic scope limitation, based on a host utility service territory, as part of its identification framework;
- that, with the exception of the application of criteria relating to rail transport, SCE has appropriately applied a reasonable set of criteria for identifying and evaluating alternatives in a manner that ensures that it has not overlooked or eliminated any clearly superior sites;
- that SCE has identified at least two practical sites with a sufficient measure of geographic diversity.

Thus, SCE generally developed and applied site selection criteria in a systematic and comprehensive manner, matching the quality of any review to date, but inappropriately limited the geographic scope of its review. Given the number and variability of the identified sites, however, the record demonstrates that it is unlikely that SCE's scope limitation resulted in SCE overlooking clearly superior sites from the perspective of most of the identified site selection criteria. With respect to the one environmental concern for which SCE's scope limitation may have been significant in overlooking superior sites -- the concern of rail traffic impacts -- the Siting Board notes that SCE's failure to adequately address such potential alternative sites warrants consideration in the weight the Siting Board places on minimizing rail traffic impacts, consistent with minimizing cost, as part of its analysis of facility impacts in Section III.C.2.vii, below. The Siting Board cautions that, to avoid consequences that potentially could involve more criteria than the one environmental concern affected in this review, future facility applicants should provide evidence that they utilized a comprehensive site selection process not limited in geographic scope, except as explicitly consistent with the Siting Board's standard of review.

Accordingly, based on the foregoing and for purposes of this review, the Siting Board finds that SCE has considered a reasonable range of practical facility siting alternatives.

C. Environmental Impacts, Cost and Reliability of the Proposed Facilities

1. Standard of Review

In implementing its statutory mandate to ensure a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost, the Siting Board requires project proponents to show that proposed facilities are sited at locations that minimize costs and environmental impacts, while ensuring a reliable energy supply. In order to determine whether such a showing is made, the Siting Board requires project proponents to demonstrate that the proposed site for the facility is superior to the noticed alternative on the basis of balancing cost, environmental impact and reliability of supply. 1993 BECo Decision, 1 DOMSB at 37-38; 1991 Berkshire Decision, 23 DOMSC at 324.

An assessment of all impacts of a facility is necessary to determine whether an appropriate balance is achieved both among conflicting environmental concerns as well as among environmental impacts, cost and reliability. Cabot Power Decision, 2 DOMSB at 389; Altresco Lynn Decision, 2 DOMSB at 177; 1993 BECo Decision, 1 DOMSB at 39; EEC Decision, 22 DOMSC at 334, 336. A facility proposal which achieves that appropriate balance is one that meets the Siting Board's statutory requirement to minimize environmental impacts. Cabot Power Decision, 2 DOMSB at 389; Altresco Lynn Decision, 2 DOMSB at 177; 1993 BECo Decision, 1 DOMSB at 39; EEC Decision, 22 DOMSC at 334, 336.

An overall assessement of the impacts of a facility on the environment, rather than a mere checklist of a facility's compliance with regulatory standards of other government agencies, is consistent with the statutory mandate to ensure a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. Cabot Power Decision, 2 DOMSB at 389; Altresco Lynn Decision, 2 DOMSB at 177; 1993 BECo Decision, 1 DOMSB at 39; EEC Decision, 22 DOMSC at 334, 336. The Siting Board previously has found that compliance with other agencies' standards clearly does not establish that a proposed facility's environmental impacts have been minimized. Id. Furthermore, the levels of environmental control that the project proponent must achieve cannot be set forth in advance in terms of quantitative or other specific criteria, but instead, must depend on the particular environmental, cost and reliability trade-offs that arise in respective facility proposals. Cabot Power Decision, 2 DOMSB at 389; Altresco Lynn Decision, 2 DOMSB at 177; 1993 BECo Decision, 1 DOMSB at 39; EEC Decision, 22 DOMSC at 334-335.

The Siting Board recognizes that an evaluation of the environmental, cost, and reliability trade-offs associated with a particular review must be clearly described and consistently applied from one case to the next. Therefore, in order to determine if a project proponent has achieved the appropriate balance among environmental impacts and among environmental impacts, costs and reliability, the Siting Board must first determine if the petitioner has provided sufficient information regarding environmental impacts and potential mitigation measures in order to make such a determination.[300] Cabot Power Decision,

[300] 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 impact 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).

In cases where a site is proposed in the coastal zone as defined by MCZM statutes and regulations, the Siting Board's Coastal Zone Facility Site Selection, Evaluation and

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2 DOMSB at 389-390; Altresco Lynn Decision, 2 DOMSB at 177; 1993 BECo Decision, 1 DOMSB at 39-40. The Siting Board can then determine whether environmental impacts have been minimized. Similarly, the Siting Board must find that the project proponent has provided sufficient cost information in order to determine if the appropriate balance among environmental impacts, costs, and reliability has been achieved. Cabot Power Decision, 2 DOMSB at 390; Altresco Lynn Decision, 2 DOMSB at 178; 1993 BECo Decision, 1 DOMSB at 40.

Accordingly, in the sections below, the Siting Board examines the environmental and cost related impacts of the proposed facilities at the Company's primary and alternative sites to determine (1) whether environmental impacts would be minimized at each site, and (2) whether an appropriate balance would be achieved at each site among conflicting environmental concerns as well as among environmental impacts and cost.[301] The Siting Board then conducts a comparison of the two sites to determine which is preferable with respect to providing a necessary energy supply for the Commonwealth at the least cost with a minimum environmental impact.

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Assessment Regulations require: (1) an environmental description of each site and its vicinity, including a review of: significant land, air, and water use; ecology; geology; hydrology; and meteorology; (2) an environmental analysis of construction impacts; (3) an environmental analysis of facility operation, including, but not limited to, land, air and water use impact, waste impacts, visual and aesthetic impacts; (4) a socioeconomic impact analysis, including measures to mitigate adverse impact during construction and operation; and (5) an analysis of all measures taken to comply with land, air, and water use and ecological standards, policies, regulations, bylaws and statutes of the Commonwealth and its political subdivisions. 980 C.M.R. § 9.02(1)(b). The Siting Board notes that both the primary and alternative sites in this review are outside of the Coastal Zone (see Section III.B.1, above).

[301] The Siting Board notes that the record in this review indicates no difference in reliability of the proposed project related to choice of the primary or alternative sites.

2. Analysis of the Proposed Facilities at the Primary Site

a. Environmental Impacts of the Proposed Facilities at the Primary Site

i. Air Quality

(A) Applicable Regulations and Methodology

The Company stated that the proposed facility would be subject to the following federal air quality rules and regulations:

1. NAAQS for Criteria Pollutants;[302]
2. Prevention of Significant Deterioration ("PSD") Increment Limits;[303]
3. MDEP Short-Term Ambient NO_2 Policy Limit;[304]
4. MDEP Air Toxics Policy Limits;[305] and

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302 The Company stated that NAAQS for criteria pollutants are health-based standards that cannot be violated at any receptor point and they apply to the total ambient concentration due to all sources emitting pollutants (Exh. SCE-8, at 4). The Company also noted that NAAQS are established for SO_2, PM-10, Nitrogen Dioxide ("NO_2"), CO, Lead ("Pb"), and Ozone ("O_3") (id.).

303 The Company stated that PSD increment limits regulate the amount that SO_2, PM-10, and NO_2 levels can be increased by new sources (Exh. SCE-8, at 5). The Company also noted that, in essence, PSD limits manage baseline air quality such that new industrial sources and general economic growth are not allowed to deteriorate baseline air quality beyond the restrictive increment amounts (id.). The Company indicated that increments apply only in areas where baseline concentrations are below the NAAQS (id.). The Company also indicated that in areas where NAAQS are violated, PSD increments do not apply since further deterioration beyond the standard is not allowed (id.).

304 The Company stated that this limit restricts 1-hour NO_2 concentrations and applies to major new sources or modifications to major existing sources which emit NOx at 250 tpy or greater (Exh. SCE-8, at 5). In reviewing the Company's air quality analysis, the Siting Board hereinafter refers to NO_2 occurring in the atmosphere as NOx, the form in which it is emitted.

305 The Company indicated that these are concentration limits applied by the MDEP to ensure that ambient concentrations of numerous non-criteria air pollutants do not

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5. BACT requirements as determined by the MDEP (Exhs. SCE-8, at 4 through 9; SCE-6, at 6-1 through 6-38).[306,307]

The Company asserted that operation of the proposed facility would comply with all federal and state air quality standards and, as such, would have acceptable impacts on air quality (Exhs. SCE-8, at 4 through 9; SCE-6, at 6-1 through 6-38).[308] In its air quality analysis, the Company determined BACT and calculated emissions for the proposed TEC consistent with federal and state requirements (Exh. SCE-3, at VI.11-1). To determine impacts on ambient air quality, the Company stated that it first assessed existing air quality and climatology and then examined PSD applicability based on potential emissions for the proposed TEC (id.). The Company indicated that it used atmospheric dispersion modeling to determine

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exceed specified levels (Exh. SCE-8, at 5).

306 The Company stated that the proposed project must meet BACT requirements in accordance with the Federal Clean Air Act ("CAA") and Massachusetts regulations (Exh. SCE-8, at 4 through 5). The Company noted that (1) under the CAA, BACT must be employed for new sources of pollutants that are subject to Federal PSD regulations, and (2) Massachusetts also requires BACT for all new or modified sources that are subject to its Air Plans Approval process (Exh. SCE-6, at 4-1).

307 The Company defined BACT as an emission limitation: (1) which is applied to regulated pollutants emitted from any proposed major stationary source or result from a major modification of an existing stationary source; (2) which is based on the maximum degree of reduction of such pollutants; and (3) which the Administrator of the EPA determines is achievable on a case-by-case basis, taking into account energy, environmental and economic impacts and other costs (Exh. SCE-6, at 5-1). The Company stated that the purpose of the BACT assessment was to determine the appropriate emission rate and control technology for the facility being permitted, not to select a fuel which would then dictate the technology (Tr. 2, at 129 through 130).

308 SCE stated that, although the existing TMLP facility stacks would be within the area of aerodynamic influence of the proposed TEC structures, SCE would provide for installation of a higher single-flue stack for the TMLP facility to ensure no adverse effects (SCE Brief at 180, citing, Exhs. SCE-1, at 4-50; SCE-6, at 6-2; EFSC-RR-26; Tr. 2, at 98).

air quality impacts,[309,310] and then assessed compliance with NAAQS, PSD increments, the Massachusetts one-hour NOx policy guideline, and the Massachusetts Air Toxics policy limits and odor thresholds (id.; Exh. SCE-6, at 6-1).[311] In addition, the Company stated that it had assessed: (1) impacts on visibility, soils, vegetation, and vegetation growth; (2) acid deposition; and (3) mitigation of impacts (id.).

In the following sections the Siting Board reviews the Company's estimates of emissions from its proposed facility as well as the impacts of those emissions on air quality. In addition, the Siting Board evaluates the impact of the proposed TEC's emissions on vegetation and soils.

(B) Identification and Control of Air Emissions

The Company stated that potential emissions of air pollutants from the proposed TEC could be divided into the two general categories, i.e., criteria and non-criteria pollutants (Exh. SCE-6, at 4-1). With respect to its discussion of non-criteria pollutants that would be

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309 The Company indicated that it had conducted an analysis for Good Engineering Practice ("GEP") stack height for its planned boiler building in accordance with EPA regulations and that a stack height of 397 feet had been chosen in keeping with GEP (Exh. SCE-6, at 6-1 through 6-2; Tr. 2, at 51).

310 The Company noted that it performed a GEP stack height analysis in advance of modeling and that, on the basis of that analysis, it designed a GEP stack to avoid aerodynamic building influences on the plume of the proposed TEC (Exh. SCE-3, at VI.11-8).

311 In response to questioning from the Attorney General, the Company agreed that it had used the second-highest values for various time periods for various pollutants in assessing project compliance with ambient air quality standards (Tr. 2, at 34 through 35). The Company asserted, however, if it had presented a table showing the highest values at these time periods for these pollutants, any increases would have been proportional for all pollutants, i.e., no one pollutant would have contributed to ambient air quality levels out of proportion to other pollutants assessed (id., at 35; Exh. AG-RR-9).

emitted by the proposed TEC, the Company noted that it had included those regulated by the EPA under PSD review as well as air toxics regulated by the MDEP (id.).[312]

With respect to determining which technologies represent BACT for the proposed project, the Company stated that it had considered two approaches to evaluating BACT, the EPA approach and the NESCAUM Guidelines (Exh. SCE-6, at 5-3 through 5-4).[313] The Company indicated that it relied principally on the NESCAUM Guidelines for its BACT analysis, but, as is standard in the EPA approach, screened out technically infeasible alternatives prior to determining cost-effectiveness (id.). The Company asserted that the proposed TEC would use technologies that represent BACT for all pollutants (id.).

(1) Description

a) Criteria Pollutants

With respect to NAAQS criteria pollutants, the Company stated that the proposed TEC would potentially emit more than 100 tpy of SO_2, NOx, CO, PM-10, VOCs, and Total Suspended Particulates (Exhs. SCE-3, at VI.11-6; SCE-5, at 4-8; SCE-6, at 4-1, 4-2).[314,315,316]

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312 The Company noted that the following were PSD non-criteria pollutants: asbestos, beryllium, mercury, vinyl chloride, fluorides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds (Exh. SCE-6, at 4-1).

313 The Company stated that the EPA approach identifies control technology alternatives for each pollutant for which BACT is required, ranks each alternative top-down by control efficiency/emission rate, eliminates alternatives which are technically infeasible, then evaluates the remaining alternatives for cost effectiveness and environmental and energy impacts (Exh. SCE-6, at 5-2). The most stringent alternative which is feasible and cost effective and which does not have significant adverse energy or environmental consequences is deemed BACT for the pollutant in question (id.). The Company also noted that the NESCAUM Guidelines call for a matrix approach to the identification and evaluation of control technology alternatives. All technologies are evaluated by economic, energy, and environmental criteria and then ranked before technologies are eliminated (id., at 5-3).

314 The Company stated that PSD new source review applies on a pollutant-specific basis in areas designated as unclassified or attainment for the various regulated pollutants

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With respect to its calculation of annual potential emission rates for criteria pollutants, the Company assumed 100 percent availability for the proposed TEC, or 8,760 hours of operation per year (Exh. SCE-6, at 4-1). The Company further indicated that emission rates were calculated based on an assumption of 100 percent maximum continuous rating (1,528 MMBtu/hr) and BACT as determined by an analysis performed by the Company (id.).[317]

(…continued)

(Exh. SCE-3, at VI.11-6). Non-attainment new source review applies in areas designated as non-attainment on a pollutant-specific basis. The Company indicated that the Taunton area is presently designated in attainment for NOx, SO_2, PM-10 and lead, and unclassified for TSP and CO (id.). In addition, the Company indicated that Massachusetts as a whole is designated as non-attainment for O_3, and that emissions of VOCs are subject to non-attainment review as precursors to ambient O_3 (id.).

315 The Company indicated that, with respect to PSD Major Source Criteria, the proposed facility is defined as major under Section 169 of the Clean Air Act of 1977 if emissions of any regulated pollutant (except those for which Taunton is classified non-attainment) are greater than 100 tpy (Exh. SCE-3, at VI.11-7).

316 The Company indicated that, although lead is included among NAAQS criteria pollutants, it had discussed lead as a non-criteria pollutant in the PSD/Air Plans Application which it had prepared for MDEP because lead, like other non-criteria pollutants, was a trace element in coal (Exh. SCE-6, at 4-1).

The Company also indicated that PM-10 background levels are conservatively assumed to be equivalent to total suspended particulates (Exh. SCE-3, at VI.11-4).

317 The Company also provided maximum hourly emission rates in pounds per hour calculated from a maximum heat input of 1,604.4 MMBtu/hr, equivalent to operation of the proposed facility at 105 percent maximum continuous rating (Exh. SCE-6, at 4-1).

The Company stated that the proposed TEC would emit SO_2 at the rate of .256 lbs/MMB[318,319] and that the proposed SO_2 emissions represented BACT (Exhs. SCE-3, at VI.11-26 through VI.11-27; SCE-8, at 5 through 6). The Company further stated that its analysis identified limestone injection to the CFB and use of medium sulfur coal, with a maximum sulfur content of 2 percent, as BACT for control of SO_2 emissions for the proposed

[318] The Company stated that it concluded that an appropriate emissions limit for BACT was 0.256 lbs/MMBtu on the basis of information available from previous BACT assessments (Tr. 2, at 30).

[319] The Siting Board notes that based on the Draft Conditional Air Permit issued by the MDEP in September 1992, SO_2 emissions will be limited to .23 lb/MMBtu and the maximum allowable coal sulfur content will be limited to 2.0 percent by weight (Exh. AG-5-45).

TEC.[320,321] The Company indicated that removal efficiency for SO_2 emissions at the proposed TEC would be 92 percent (Exh. SCE-6, at 5-40).[322],[323]

The Company asserted that neither the use of wet nor dry scrubbing, nor the use of low sulfur coal with limestone injection would be cost-effective for the proposed TEC, and, therefore, neither would represent BACT (id. at 5-41; Tr. 2, at 28 through 36). In support of its assertion, SCE provided results of an analysis of the use of lower sulfur coals, conducted as part of SCE's fuel procurement strategy (Exh. SCE-12, at 2). The Company stated that, in soliciting bids, it sought information about 1 to 1.5 percent coal (low sulfur coal); 1.5 to 1.8 percent coal (low-medium sulfur coal); and 2.0 to 2.5 percent sulfur coal (medium sulfur coal) (id. at 5). From the bids received, the Company testified that it selected a 1.8 percent sulfur

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320 In support of its proposed SO_2 emission limit, the Company provided, as a basis for comparison, a range of SO_2 values, .25 to .32 lb/MMBtu, based on recent permit applications of five new and proposed coal-fired facilities in the Northeast (Exh. SCE-5, at 4-7; Tr. 2, at 28 through 36).

321 The Company indicated that two percent sulfur content coal corresponded to the BACT outcome indicated (Tr. 2, at 30).

322 The Company stated that, under current technology, two percent sulfur content coal would result in 92 percent sulfur removal at 12,500 Btu's per pound (Tr. 2, at 31). The Company further stated that sulfur removal for the proposed TEC would be lower than the 93.9 percent sulfur removal efficiency at the Half-Moon Cogeneration Project in New York because the proposed TEC would use lower sulfur coal than the Half Moon facility (id. at 31 through 33). The Company asserted that BACT is determined on a case-by-case basis, and that two very similar projects at different locations might come to a different conclusion on BACT (id. at 33). The Company testified that its estimate of 90 percent sulfur removal for 1.2 percent sulfur coal was based on empirical information from boiler vendors and that vendor guarantees of removal efficiency would vary depending upon the sulfur content of the coal used (id. at 34; Exh. AG-RR-8).

323 SCE stated that, although cost-effectiveness on a guaranteed basis remains uncertain, available information indicates that higher sulfur capture of 93 percent may be achievable with vendor guarantee at operating costs of $1,000 to $1,540 per ton of SO_2 emission avoided (SCE Brief at 189, citing, Exh. EFSC-E-42; Tr. 5, at 35 through 41, 86 through 90).

coal which in fact offered a lower total cost than the 2.0 percent sulfur coal identified as BACT (Tr. 5, at 13 through 16). The Company asserted, however, that the relationship between the fuel procurement and BACT analyses in this case was unique because there were no incremental costs associated with selecting the lower -- 1.8 percent rather than 2.0 percent -- sulfur coal and that, therefore, the BACT analysis remained unchanged with respect to SCE's ability to achieve the BACT emission rate in a cost-effective manner (SCE Brief at 185). See Section III.C.2.b, below.

With respect to the sulfur content of coal and BACT for SO_2, the Attorney General contested the Company's assertion that 2.0 percent sulfur coal would constitute BACT (Attorney General Brief at 140 through 142). The Attorney General argued that the use of 2.0 percent sulfur coal would not be adequate to minimize SO_2 emissions of the proposed TEC since: (1) reducing the sulfur content of coal used for the proposed TEC would also reduce sulfur emissions from the proposed facility; (2) SCE expected to sign a contract which would provide the proposed TEC with 1.8 percent maximum sulfur content coal; and (3) costs for 1.8 percent sulfur coal would be lower than costs for 2 percent coal (id.; Tr. 2, at 10 through 12; Tr. 5, at 13 through 14, 71; Exh. SCE-12, at 6 through 7).

With respect to NOx emissions, the Company proposed a BACT of .15 lb/MMBtu (Exh. SCE-3, at VI.11-27). The Company stated that its selection of CFB technology would hold the formation of NOx in the combustion process to approximately .3 lb/MMBtu, below the federal New Source Performance Standards ("NSPS") limit of .6 lb/MMBtu (id.).[324] To achieve a NOx emission rate below .3 lb/MMBtu, the Company proposed to install an add-on pollution control system which would reduce NOx emissions to .15 lb/MMBtu (id.).

In evaluating options for add-on pollution control systems, the Company considered SNCR and SCR technologies (Exh. SCE-6, at 5-10 through 5-13, 5-23 through 5-27). The

[324] The Company indicated that there are three commercially available technologies for control of NOx from the combustion process: (1) low temperature staged combustion; (2) SCR, and (3) SNCR (Exh. SCE-6, at 5-9). The Company stated that low temperature combustion is inherent to the CFB and is considered the base technology (id.).

Company stated that not only had a global search failed to identify a single CFB unit using SCR for NOx control, but, in addition, its analysis indicated that SCR is not a technically feasible alternative for control of NOx from a CFB unit combusting eastern bituminous coal (id. at 5-25).

With respect to SNCR technologies, the Company's analysis indicated that two SNCR processes were available domestically, one using ammonia and the other using urea as a reducing agent to convert NOx to nitrogen and water (id. at 5-10). The Company indicated a strong preference for use of ammonia as a reagent, based on (1) greater experience with ammonia for large coal-fired CFB units, and (2) the estimated greater expense of using urea (id.; Tr. 6, at 24 through 26; Exh. AG-RR-18).

With respect to emissions of VOCs, the Company indicated that VOC emissions result from the combustion process, but that most VOCs are completely combusted in the CFB process (Exh. SCE-6, at 5-35). The Company noted, however, that some VOCs are invariably emitted from the CFB unit because they volatize below, but ignite above, the temperature of the combustion bed (id. at 5-17). The Company stated that there are no NSPS or MDEP limits for VOCs, and asserted that the rate of VOC emissions anticipated for the proposed facility, a maximum of .007 lb/MMBtu[325] -- resulting in potential emissions of 49 tpy, would constitute BACT (Exh. SCE-5, at 4-7 through 4-8; Tr. 6, at 35 through 37).[326,327,328]

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325 Based on the Draft Conditional Air Permit issued by the MDEP in September 1992, VOC emissions will be limited to .006 lb/MMBtu (Exh. AG-5-45).

326 The Company indicated that the level of combustion of VOCs was a function of individual boiler design (Tr. 6, at 37). The Company further indicated that its assumptions regarding the extent to which VOC emissions could be reduced were based on information and guarantees from boiler vendors (id.).

327 The Company stated that there were no VOC control techniques for coal-fired CFB projects in the United States that might represent Lowest Achievable Emission Rates but not BACT (Exh. EFSC-RR-33). The Company asserted that the only technically feasible option for further reducing VOCs in a CFB unit would be to optimize CFB combustion conditions specifically to control VOCs (id.). The Company asserted that

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As BACT for CO, the Company proposed combustion control in the CFB (Exh. SCE-6, at 5-4).[329] The Company stated that add-on controls were not available for the control of CO emissions (Exh. SCE-3, at VI.11-27). The Company asserted that optimizing the combustion process for the control of CO emissions in the CFB would minimize emissions of CO, and proposed a CO emission level of .18 lb/MMBtu (id.; Exh. SCE-5, at 4-8).[330]

With respect to particulate matter, including PM-10 from combustion of coal in the CFB, the Company proposed the use of fabric filter bags as BACT (Exh. SCE-6, at 5-4). The Company stated that use of fabric filter bags would limit emissions of particulate matter, including PM-10,[331] to less than .018 lb/MMBtu (Exh. SCE-3, at VI.11-28). As an alternative to using fabric filter bags, the Company analyzed the effectiveness of particulate control, as

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such optimization could occur only at the expense of controlling other pollutant emissions (id.).

328 The Company indicated that the estimates of VOC emissions reported in its PSD/Air Plans Application (Exh. SCE-6) and in its Final Environmental Impact Report (Exh. SCE-5) included VOC emissions from the proposed CO_2 facility associated with the proposed TEC (Exh. EFSC-E-12).

329 The Company stated that CO is a product of incomplete combustion; that reduction efforts have centered on promoting more complete combustion; and that the CFB uses staged combustion to reduce CO while avoiding increases in NOx (Exh. SCE-6, at 5-34 through 5-35). The Company noted that thermal oxidation of nitrogen to NOx occurs as combustion temperatures are increased to promote more complete combustion (id.). The Company indicated that, in staged combustion, to prevent the unwanted increase in NOx, fuel is volatilized in a reducing atmosphere (id.). Volatile components are then combusted in an oxygen-rich zone downstream (id.).

330 Based on the Draft Conditional Air Permit issued by the MDEP in September 1992, CO emissions will be limited to .13 lb/MMBtu for facility operation at 70 percent to 100 percent of capacity and would increase with facility operation at lower capacities (Exh. AG-5-45).

331 The Siting Board notes that the Draft Conditional Air Permit issued by the MDEP limits emissions of particular matter, including PM-10 to 0.018 lb/MMBtu (Exh. AG-5-45).

well as cost, of another available filter bag, but determined that the alternate bag was not necessarily more effective at removing particulates than were the proposed felted fiber bags (Tr. 6, 13 through 15; Exh. EFSC-RR-31).[332]

With respect to emissions of particulates from handling and storage of coal, limestone, and ash, the Company stated that dust collectors would be used to control emissions (Exh. SCE-6, at 5-19).[333] The Company also indicated that all conveyors and the coal storage building would be fully enclosed (id.). In addition, the Company stated that coal delivered to the proposed TEC in rail cars would be coated with a special latex binder to seal the coal surface, and that all ash leaving the facility in rail cars would be pelletized into dust-free pellets (id.). The Company stated that, for each of the above sources of particulates, its proposal constituted BACT for control of particulates, including PM-10 (Exh. SCE-6, at 5-20).

b) Other Pollutants

The Company indicated that it considered emission levels for non-criteria pollutants that both (1) were on the MDEP air toxics list, and (2) might be emitted by the proposed TEC (Exh. SCE-6, at 4-1). The Company stated that MDEP non-criteria pollutants selected for consideration were: beryllium, cadmium, chromium, chromium (VI), copper, fluoride,

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332 The Company stated that, for control of particulates including PM-10, its proposed use of felted fiber bags would be significantly less costly than use of Gore-Tex bags, the available alternative (Exhs. AG-RR-18; AG-RR-19; EFSC-RR-32; Tr. 2, at 123 through 125). The Company indicated that there was, to date, inadequate testing of the effectiveness of Gore-Tex bags, and that, in any case, control effectiveness of either Gore-Tex or felted fiber bags depended on design and operation variables of individual facilities (Exh. EFSC-RR-62; Tr. 6, at 13 through 15). See Section III.C.2.b, below.

333 The Company stated that dust collectors would be used to control emissions from the coal handling system, particularly at the coal storage and boiler buildings, at the conveyor to the coal crusher, and at the rail car unloading area (Exh. SCE. 6, at 5-19). With respect to the ash handling system, the Company stated that dust collectors would be used to control emissions from ash pelletizing, as well as from the ash storage silo and ash load-out silo (id. at 5-20). With respect to the limestone handling system, the Company indicated that dust collectors would control emissions from the limestone storage silo (id.).

hydrogen chloride, hydrogen fluoride, lead, nickel, nickel oxide, selenium, vanadium, vanadium pentoxide, sulfuric acid, ammonia, and formaldehyde (id.).[334,335] The Company also identified CO_2 as a non-criteria pollutant which would be emitted by the proposed facility (Exhs. EFSC-E-10; SCE-18, at 3 through 4).

The Company estimated emission levels from the proposed facility of non-criteria pollutants and trace pollutants, based on available literature on trace element concentrations in Eastern Bituminous coal (id. at 4-4).[336] The Company noted that emission levels would be affected by (1) the variability in the trace element content in Eastern Bituminous coal, as well as by (2) the variation in the rate at which the metals volatilize and divide between flyash and bottom ash (id.).[337] The Company proposed limestone injection to control acid gases, use of a fabric filter to control particulates containing heavy metals, and maintenance of a low operating temperature at the fabric filter inlet to condense trace metals for capture in the fabric filter as BACT for reducing non-criteria pollutants, including lead (id., at 5-17 through 5-19, 8-1).[338]

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334 The Company stated that it did not consider emission rates for the remaining non-criteria pollutants listed by MDEP, asbestos, vinyl chloride, hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds, because no emissions from these pollutants was expected from the combustion of coal or material handling of coal, ash and limestone (Exh. SCE-6, at 4-4).

335 The Company noted that, because emissions of beryllium and mercury from the proposed TEC would exceed the established de minimis criteria, these trace elements would be included among those pollutants requiring PSD review (Exh. SCE-6, at 4-9). The Company further noted that BACT review is required by the EPA for each of the PSD applicable pollutants (id.).

336 The Company noted that coal generally exhibits considerable variability in trace element characteristics and content even from seam to seam within a given mine (Exh. SCE-6, at 4-4).

337 The Company noted the difficulty both in controlling, and in estimating the emissions of metals such as mercury, which remains a vapor throughout the combustion process (Exh. SCE-6, at 4-4).

338 With respect to lead, the Company indicated that it anticipated lead emissions of 3.0 x

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With respect to CO_2 emissions, the Company stated that with one reheat boiler, the CO_2 emission rate of the proposed TEC would be 156 tons per hour or 1.15 x 10^6 tons per year (id.). The Company stated that its reconfiguration of the proposed TEC to use one reheat boiler, rather than two non-heat boilers, resulted in a lower rate of CO_2 emissions (Exh. EFSC-E-10).

The Company noted that its CO_2 emission estimate did not reflect extraction of CO_2 by the proposed CO_2 facility (id.). The Company stated that the proposed CO_2 facility would extract approximately 150 tons of CO_2 per day, or approximately 50,000 tons per year (id.).

The Company noted that state and federal air quality regulations do not establish emissions limitations for CO_2 (Exh. SCE-18, at 3). In addition, the Company noted that there is ongoing debate regarding the potential effects of atmospheric concentrations of gases such as CO_2 (id., at 3 through 4; Tr. 2, at 193 through 195). The Company stated, however, that it recognized that CO_2 emissions from generating facilities are not insubstantial, and that no control technologies can be incorporated into the design of the proposed TEC to minimize CO_2 emissions (Exh. SCE-18, at 3).

The Company further stated that it had analyzed a range of CO_2 offsets and a variety of strategies for attaining them, including reforestation, forest preservation, decreasing automobile traffic, destruction of chlorofluorocarbons, and landfill methane mining (id., at 4 through 5, Att. 2). SCE asserted that CO_2 mitigation programs which it had examined, other than open-space conservation and tree-planting, would have a serious adverse impact on the financial viability of the proposed TEC (Exh. SCE-18, at 3 through 6).

The Company initially proposed a 40-year, $640,000 tree planting and open-space conservation program in the Taunton area, asserting that the program would offer mitigation impacts equivalent to those of the Massachusetts ReLeaf ("MASS ReLeaf") tree-planting program (Exh. SCE-18, at 4; Exh. SCE-3, at VI.11-29; Exh. SCE-5, at 5-26; EFSC-E-10; Tr. 2, at 159 through 161). The Company stated that the rough NPV of its originally proposed

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10^{-5} lb/MMBtu from the proposed TEC (Exh. SCE-6, at 4-5).

tree planting program would be $150,000 over the life of the plant (Exhs. EFSC-E-10(b); SCE-18, at 4). The Company further stated that, on the basis of the EEC Compliance Decision, SCE proposed to provide additional funds to MASS ReLeaf or a credible reforestation program within the first five years of facility operation, NPV of such funds to equal $500,000 (SCE Brief at 218 through 219). The Company indicated that the NPV of its total commitment for CO_2 mitigation would be $650,000 (id.).[339]

With respect to mitigation of CO_2 emissions, the Attorney General argued that SCE's proposed tree-planting program fails to mitigate the CO_2 emissions of the proposed TEC adequately, and that SCE should provide offsets at a level commensurate with those required in the EEC Compliance Decision (Attorney General Brief at 135). The Attorney General noted that SCE estimated that the proposed TEC would emit 1,150,000 tpy of CO_2, less the approximately 50,000 tpy for the adjacent CO_2 facility, assuming its operation as proposed, resulting in a net quantity of 1,100,000 tpy of CO_2 (id. at 136; Exh. EFSC-E-10(a)). The Attorney General declared that CO_2 removal from the atmosphere which SCE anticipated from its CO_2 mitigation scheme, 135,000 tons, was a small fraction of anticipated CO_2 emissions over the 40-year life of the proposed TEC (id. at 136 through 137; Exh. WG-T-8A; Tr. 2, at 186). The Attorney General also declared that the degree of CO_2 mitigation which would result from the land-purchase and tree-planting elements of SCE's CO_2 mitigation scheme could not be determined (Attorney General Brief at 137; Tr. 2, at 161 through 162; Tr. 6, at 62 through 63). The Attorney General further argued that other CO_2 mitigation schemes were superior to the CO_2 mitigation strategy proposed by SCE (Attorney General Brief at 138 through 139).

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339 The Company noted that, in the EEC Compliance Decision, the Siting Council accepted contributions to MASS ReLeaf as mitigation of CO2 emission impacts (SCE Brief at 214). In its decision, the Siting Council also: (1) increased EEC's contribution to $2 million; (2) required the contribution to be shared between MASS ReLeaf and a credible reforestation program; and (3) required EEC to make these contributions in full within five years of commencement of operation of the proposed facility (SCE Brief at 218 through 219; EEC Compliance Decision, 25 DOMSC at 68).

c) Predicted Impacts

In order to assess compliance with ambient air quality standards, PSD increment limits, the MDEP air toxics policy and one-hour NOx guideline, SCE stated that it evaluated air quality impacts from operation of the proposed TEC (Exh. SCE-3, at VI.11-8 through VI.11-9). The Company stated that to estimate potential impacts on air quality, it relied on two standard atmospheric dispersion computer models recommended by the EPA and MDEP, the Industrial Source Complex Short-Term ("ISCST") model, and the VALLEY screening model (id.).[340,341,342]

The Company stated that, as required by EPA regulations, it had carried out a GEP stack height analysis of its proposed boiler, and that this analysis was performed in advance of modeling (Exhs. SCE-3, at VI.11-8; SCE-6, at 6-1 through 6-2). The Company provided its final estimates of ambient air quality impacts on the basis of a single reheat boiler and GEP stack height of 397 feet (Exhs. SCE-5, at 4-8; SCE-6, at 6-1 through 6-2; Tr. 2, at 51). The Company stated that for ash, coal, and limestone process handling sources of particulate

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340 The Company indicated that these models are mathematical formulation models and associated algorithms, codified in computer programs, that simulate plume transport and diffusion, and then calculate projected concentrations at various ground level locations (Exh. SCE-3, at VI.11-8 through VI.11-9). The Company stated that the ISCST model, version 90346, was selected because it could handle multiple sources, simulate interaction with terrain at elevations up to stack top, and simulate the aerodynamic effects of nearby buildings and structures (id.). The Company indicated that the VALLEY model, version 85338, was used for receptor terrain elevations above stack top (id. at VI.11-9).

341 The Company stated that it also classified land uses around the proposed TEC prior to initiating dispersion modeling, and determined that the project area was rural for air quality modeling purposes on the basis of MDEP recommended procedures (Exhs. SCE-3, at VI.11-8; SCE-6, at 6-9).

342 The Company stated that, on the basis of discussions with TMLP, the Company will replace the existing 185-foot TMLP stacks with a new 249-foot single shell multi-flue stack and that it had used the proposed new stack in its subsequent refined ISCST modeling (Exh. SCE-6, at 6-2).

emissions, all of which fall below the 397 foot GEP height, building downwash from adjacent structures was accounted for in the air quality modeling (Exh. SCE-6, at 6-2).

SCE stated that modeling of emissions at the proposed TEC indicated that total ambient concentrations for SO_2, PM-10, NOx, Pb and CO would be below NAAQS, even when using conservative background levels (id. at 6-26). The Company further stated that impact of the proposed TEC on total ambient concentrations would also comply with NSPS and PSD review (Exhs. SCE-3, at VI.11-13; SCE-8, at 4 through 6; SCE-6, at 6-5, Table 6-3). The Company indicated that it had also used air quality modeling results to evaluate compliance with all MDEP Air Toxic Policy limits. The Company further indicated that the results of its modeling indicated that all 24-hour and annual levels from the proposed TEC would be below the established AALs (Exh. SCE-6, at 6-28; Tr. 2, at 34 through 35). The Company asserted that its air quality dispersion modeling demonstrated compliance with all applicable federal and state standards and policies (Exh. SCE-6, at 8-2).

With respect to possible effects of fogging or icing from the cooling tower plume, SCE stated that it had used the standard EPRI-sponsored Seasonal/Annual Cooling Tower Plume Impact model to evaluate impacts (Exh. SCE-5, at 46 through 47). The Company stated that, on the basis of its analysis, no adverse impacts were anticipated from fogging and icing resulting from the proposed cooling tower plume because effects would occur (1) infrequently, (2) predominantly within project site boundaries, and (3) with minimal impact on public roadways (id.).

With respect to impacts of air emissions from the proposed facility on vegetation and soils, SCE analyzed air quality impacts on sensitive vegetation types and soils in accordance with PSD regulations (Exh. SCE-6, at 6-32). The Company indicated that its analysis was performed by comparison of predicted facility impacts with screening levels presented in an EPA guidebook on such screening (id.).[343] SCE stated that, with the exception of SO_2, most of

343 SCE provided the following reference for the EPA guidebook used for its comparison: U.S. EPA, A Screening Procedure for the Impacts of Air Pollution Sources on Plants, (continued...)

the vegetation screening levels designated in the guidebook were equivalent to, or less stringent than, NAAQS and/or PSD increments (id., at 6-34). The Company asserted that satisfaction of NAAQS and PSD increments would, therefore, assure compliance with vegetation screening levels except for SO_2 (id.). The Company further indicated that no NAAQS or PSD exceedances were anticipated for the proposed project (id.).

For SO_2 emissions, the Company stated that specific calculations were made because (1) for the 3-hour and annual SO_2 averaging periods, sensitive vegetation screening levels are more stringent than the standards required by NAAQS, and (2) the screening guidebook includes a 1-hour screening level for SO_2 for which there is no NAAQS equivalent (id. at 34 through 35). SCE indicated that the results of its calculations demonstrated that although predicted 1-hour and 3-hour SO_2 concentrations from the proposed TEC would be well below the SO_2 sensitive vegetation screening levels, they would represent an addition to annual background SO_2 concentrations already equal to the screening levels for SO_2 (id.). The Company stated, however, that the contribution of the proposed TEC to the annual averaging period would be below significance criteria and would represent less than 3 percent of the predicted annual ambient concentration (id.). SCE asserted that, therefore, the proposed TEC would not exacerbate existing impacts of SO_2 emissions on sensitive vegetation (id.).

With respect to potential effects of trace elements deposited on soils, SCE stated that it used EPA screening techniques to evaluate potential impacts from the proposed TEC. The Company stated that its analysis indicated that all soil concentrations resulting from the proposed TEC would fall below EPA-recommended screening levels (id. at 36 through 38).

(2) Analysis

The Siting Board notes that the federal and state air quality rules and regulations apply to the quantity of pollutants that will be emitted and to the impact of such emissions on the ambient air quality. The record demonstrates that all federal and state regulated emissions from

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Soils, and Animals, EPA 450/2-81-078, December 12, 1980 (Exh. SCE-6, at 6-32).

the proposed project will satisfy applicable air quality regulations; however, two pollutants, SO_2 and CO_2, raised particular concern regarding impacts on air quality and SCE's proposed plans to mitigate such impacts. Based upon the record in this case, the Siting Board finds that the other pollutants from the proposed plant would not add significantly to the existing air pollutant concentrations and are adequately minimized.[344]

The Siting Board, however, shares the concern of the Attorney General that the Company has not demonstrated that SO_2 emissions have been adequately minimized. While the Siting Board recognizes that the ultimate selection of coal for a project may rest on considerations other than sulfur content,[345] the Siting Board also recognizes that the sulfur content of coal burned in a coal-burning facility is a determinant, in part, of the amount of sulfur that the facility will emit. The Siting Board notes that, in its analysis, in addition to the use of limestone injection to the CFB, the Company identified use of medium sulfur coal with a maximum sulfur content of 2.0 percent as BACT for control of SO_2 emissions for the proposed TEC. However, SCE expects to use coal with a sulfur content of 1.8 percent, and would use 2.0 percent sulfur coal only on a force majeure basis. Further, SCE expects the average sulfur content of its coal to be 1.6 percent for at least the early years of the contract -- well within the 1.5-to-1.8 percent low-medium sulfur content category.

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344 The Siting Board notes that two other pollutants, VOCs and PM-10, were of some interest in this proceeding. With respect to VOCs, however, the record demonstrates that SCE expects to achieve an emission rate for VOCs no higher than .007 lb/MMBtu including emissions from the proposed CO_2 facility, and would be required by DEP to achieve .006 lb/MMBtu from the CFB boiler, a result of combustion control technology inherent to its proposed CFB unit. The Siting Board notes that VOC emissions from the proposed facility would, therefore, be within the .005 lb/MMBtu to .007 lb/MMBtu range found acceptable for impacts of VOCs by the Siting Council in the EEC Decision. 22 DOMSC at 356. With respect to PM-10, the record shows that two control measures for removing PM-10 from CFB combustor emissions, a felted fiber baghouse and Gor-Tex bags, were considered, that no clear advantage in the use of Gore-Tex bags for capture of PM-10 was demonstrated, and that the use of felted fiber baghouses would adequately minimize emissions of PM-10 for the proposed facility.

345 The Siting Board notes that cost, heat potential, and quantity of a given coal available are all examples of other considerations which may influence coal selection.

Nonetheless, SCE has not proposed to use 1-to-1.5 percent low sulfur coal, which it identified as an available, albeit higher cost option, in spite of the fact that such coal would result in reductions in SO_2 emissions beyond those from the low-medium sulfur coal proposed by the Company.[346]

Accordingly, the Siting Board finds that the Company has not established that SO_2 emissions would be minimized for the proposed TEC at the primary site. The Siting Board considers whether the Company's proposed use of 1.8 percent sulfur coal is justified based on cost considerations in Sections III.C.2.b. and II.C.2.c, below.

With respect to an analysis of CO_2 impacts, the Siting Board notes that the Siting Council first established in the Enron Decision the requirement that all applicants of proposed facilities that emit CO_2 must comprehensively address the mitigation of CO_2 impacts. 23 DOMSC at 196. In the EEC Compliance Decision, the Siting Council further provided that future applicants must present alternative CO_2 mitigation plans, including likely arrangements for ensuring implementation and verification of estimated results, to demonstrate that all cost-effective approaches have been adequately considered. 25 DOMSC at 358-360.[347]

The Siting Council also set forth in the EEC Compliance Decision general criteria it considers to determine the adequacy of CO_2 mitigation in such reviews, as well as approving a

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346 In a prior decision, the Siting Council evaluated the use of low sulfur coal in a CFB facility. EEC Compliance Decision, 25 DOMSC at 335-348. In that decision, the Siting Council accepted the use of 2.4 percent sulfur coal based on a comparative analysis of the cost of using 2.4 and 1.8 percent sulfur coal which indicated that the Company would be able to acheive sulfur emission reductions at other facilities greater than those associated with the use of 1.8 percent sulfur coal with money saved from use of 2.4 percent sulfur coal at its proposed facility (id.). Nevertheless, the cost-effectiveness of various coals must necessarily be project specific, and, therefore, acceptance of 2.4 percent sulfur coal -- or any other sulfur content coal -- cannot automatically be applied in the present proceeding or to subsequent reviews.

347 The Siting Council also stated that it would be preferable for applicants to address the adequacy of CO_2 mitigation in terms of the quantity of CO_2 emission offsets to be attained rather than in terms of the cost to be committed for providing CO_2 emission offsets. EEC Compliance Decision, 25 DOMSC at 362.

particular cost commitment for that project.[348] Id. at 361-367. The Siting Council noted that, in determining the appropriate CO_2 mitigation level based on identified criteria, it considers the balance between the interest of CO_2 mitigation and other interests including cost, viability, other environmental mitigation and any facility benefits such as supply diversity. Id. at 365.

In its recent review of two gas-fired cogeneration facilities, where the initial filing predated the above holdings, the Siting Board recognized that a determination of an appropriate level of CO_2 offsets should bear a reasonable relationship to the level of CO_2 offsets required of EEC in the EEC Compliance Decision. Cabot Power Decision, 2 DOMSB at 400 through 403; Altresco Lynn Decision, 2 DOMSB, at 217 through 218.[349] Thus, the Siting Board

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348 The Siting Council stated that it may consider various relevant project factors -- for example facility cost, facility CO_2 emissions, and any increment of such emissions exceeding the emissions of displaced capacity ("net-of-displacement emissions") -- in order to determine the appropriate level of CO_2 mitigation for proposed facilities. EEC Compliance Decision, 25 DOMSC at 365. In establishing that both total emissions and net-of-displacement emissions could be appropriate indicators, the Siting Council noted that it may not be clear as to whether a proposed facility would serve primarily to displace existing power generating facilities or to meet future load growth. Id. at 363. The Siting Council recognized that, to determine the appropriate level of CO_2 mitigation, it is necessary to relate a proposed facility's CO_2 emissions to net changes in regional or national emissions. Id. To the extent that a proposed facility would displace existing power generating facilities, there may be a beneficial or adverse impact on regional or national levels of CO_2 emissions corresponding to the difference between such proposed facility's emissions and those of the displaced generation. Id. To the extent that a proposed facility is to be built in whole or in part to meet load growth, new generation may be added to the region's supply faster than old generation is retired or otherwise displaced. Id. In this latter situation, the net impact of a proposed facility on regional/national CO_2 emissions may not correspond to the difference between its emissions and those of any alternative energy resource, but rather may reflect more closely the total CO_2 emissions from such proposed facility. Id.

349 In both of these cases, the Siting Board recognized that to the extent the proposed facility would serve to displace existing generation, its expected CO_2 emissions would be exceeded by those from displaced capacity. In contrast, the required CO_2 offsets in the EEC Compliance Decision were a small fraction of that facility's net-of-displacement emissions, assuming the project would serve to displace existing

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required an increase in the proposed level of CO_2 offsets in those cases such that 0.348 percent of facility emissions would be offset. Cabot Power Decision, 2 DOMSB at 401; Altresco Lynn Decision, 2 DOMSB at 220.[350,351]

The Company's initial filing in the present proceeding predated the above holdings concerning both analytical requirements and an appropriate level of offsets for CO_2 impacts, but because these holdings coincided with the present proceedings, the Company submitted supplemental testimony and analysis with respect to CO_2 offsets which reflected the Siting Council's directives in the Enron Decision and the EEC Compliance Decision. The Siting Board notes that the Company, by evaluating various reasonable strategies for offsetting CO_2 impacts in addition to the tree-planting program it now proposes, has undertaken an analysis of alternative mitigation for impacts of CO_2 emissions which is adequate for this review.

Here, SCE's proposed facility would emit 1,100,000 tpy of CO_2. Based on the approximate percentage of total emissions reflected in the offset requirement in the EEC Compliance Decision, i.e, 0.8 percent, SCE's offset requirement would be 8800 tpy. However, recognizing the limited tree clearing necessary for the proposed facility, the net offset requirement for the Altresco and Cabot projects of .348 percent would be more appropriate for the proposed TEC, resulting in an offset requirement of 3828 tpy. The Company's expenditure

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generation. 25 DOMSC at 366.

350 In the Altresco Lynn Decision, the Siting Board recognized that, based on the assumption that a planted tree would provide 0.75 tpy of CO_2 offsets, the required CO_2 mitigation in the EEC Compliance Decision would offset approximately 0.8 percent of that facility's CO_2 emissions. 2 DOMSB at 212. The Siting Board also recognized, however, that on-site tree clearing would partially negate offsets, reducing them to 0.348 percent of facility emissions. See, EEC Compliance Decision, 25 DOMSC at 350, 354, 366-367; Cabot Power Decision, 2 DOMSB at 425.

351 With respect to tree planting costs, the Siting Board has recognized a cost of $100 per tree under the MASS ReLeaf program. Cabot Power Decision, 2 DOMSB at 425; Altresco Lynn Decision, 2 DOMSB at 219; EEC Compliance Decision, 25 DOMSC at 350.

of NPV $500,000 would allow the purchase of 5000 trees at $100 each, accounting for a CO_2 reduction, at .75 tpy per tree of 3750 tpy. The remaining 78 tpy of CO_2 mitigation would require planting of 104 more trees, accounting for NPV $10,400 from the additional NPV $150,000 which SCE has allotted for tree planting and open space conservation. Assuming, therefore, that the Company expends at least NPV $510,400 for tree-planting, in equal annual installments over the first five years of facility operation or sooner, the Company's proposed mitigation should provide adequate CO_2 emission offsets consistent with those required in the EEC Compliance Decision, the Altresco Lynn Decision, and the Cabot Power Decision.

Thus, on the basis of the guidelines for offsets of CO_2 emissions established by the Siting Board in previous generating facility cases, the Company has established that its proposed CO_2 offset plan would provide an acceptable level of mitigation of CO_2 emissions from the proposed TEC at the primary site. The Siting Board expects, however, that in the event that the cost associated with the plan varies significantly such that the proposed spending level would not acheive the minimum .348 percent required, SCE will provide sufficient additional CO_2 mitigation to offset 0.348 percent of the CO_2 emissions from the proposed facility. See, Cabot Power Decision, 2 DOMSB at 427; Altresco Lynn Decision, 2 DOMSB at 220.

Accordingly, based on the foregoing, the Siting Board finds that, with the implementation of SCE's proposed BACT and CO_2 mitigation, and with the exception of SO_2 emissions, the Company has established that the environmental impacts of the proposed facility at the primary site would be minimized with respect to air quality.

ii. Water Resources (Wetlands and Waterways)

(A) Description

The Company stated that it had identified seven wetland areas, as defined by the Massachusetts Wetlands Protection Act ("WPA"), on, or adjacent to, the TMLP primary site

(Exh. SCE-3, at VI.1-1).[352,353] See, G.L. c. 131 § 40; 310 C.M.R. § 10.00. The Company indicated that these wetland areas comprise approximately 25 percent of the 100-acre primary site, and include a portion of an extensive wetland bordering the Taunton River and several smaller wetlands separated from the Taunton River by the former rail bed and other upland areas (id. at III.2-4).

The Company asserted that the proposed project had been designed to avoid wetlands protected under the WPA and would not directly alter any wetland areas (Exh. SCE-13, at 10; Tr. 3, at 38).[354] The Company noted, however, that some construction activities, including those related to the cooling tower and discharge outlet, rail access, and the main access road, would result in limited temporary vegetation impacts in wetland areas, and some disturbance to buffer zones adjacent to these wetland areas (id.). The Company asserted that a full range of impact mitigation techniques would be used to minimize damage to wetland areas and buffers

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352 The Company indicated, in addition, that wetlands were delineated using the mandatory criteria established under the "Federal Manual for Identifying and Delineating Jurisdictional Wetlands" (Exh. SCE-3, at VI.1-1).

353 The locations of the seven identified wetlands are described as follows: one wetland is east of the railroad spur bordering on the existing discharge canal and the Taunton River; two wetlands, a wet meadow and a swamp, separated from each other by a drainage divide, lie south of TMLP's existing access drive; one wetland, off-site, adjacent to Railroad Avenue, has a buffer zone which encompasses a portion of the railroad siding; two wetlands lie to the west of the railroad, one located just west of the railroad siding within the limits of the former gravel operation, the other largely off TMLP property but positioned to collect stormwater runoff from TMLP grounds; and, finally, one wetland, a wet meadow/swamp, is located in the extreme northeast corner of the TMLP property, on the north side of the existing access drive, and adjacent to an existing parking lot (Exh. SCE-3, at III.2-4, VI.1-2 through VI.1-4).

354 The Company stated that a Notice of Intent describing the Company's compliance with requirements for wetlands protection had been filed with, and approved by, the Taunton Conservation Commission (Exh. SCE-13, at 10). The Company stated that the proposed project would be constructed in accordance with the Order of Conditions issued by the Taunton Conservation Commission, and that, following project completion, it would apply for a Certificate of Compliance specifying proper observance of the Order of Conditions (Exh. SCE-3, at IV.3-3).

both during and after construction (Exh. SCE-7, at 20 through 22).[355] With respect to the impacts of buffer zone alterations on wetlands, the Company stated that it developed its mitigation approach not in terms of specific setback distances from wetlands, but in terms of avoiding drainage impacts on wetlands (Tr. 3, at 38).

The Company stated that the two wetlands to the west of the railroad siding were subject to jurisdiction under the Federal Clean Water Act (Exh. AG-2-13, at C-6).[356] The Company stated that the man-made wetland would be replaced by a stormwater management basin, which would maintain the existing flood control and sedimentation stabilization functions of the wetland (Exh. SCE-7, at 20 through 22).[357,358]

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355 The Company indicated that its precautions with regard to wetlands would include the following measures: wetland areas would be flagged; no staging area would be constructed in bordering vegetated wetlands; siltation barriers would separate wetland areas from work areas; excavated soil would be appropriately stockpiled; construction would not be scheduled adjacent to banks and surface water during periods of high flow or inclement weather; banks would be stabilized quickly using either riprap or vegetation; periodic inspections would occur to ensure proper siltation control; native vegetation would be used whenever possible; removal of siltation barriers would occur once vegetation has been established and would be done by hand; periodic reinspections of vegetation would be conducted throughout the two growing seasons following proposed project completion; catch basins with sedimentation chambers would be installed to improve water quality where drainage systems discharge into a detention basin or wetland; and compensatory flood storage areas would be developed (Exh. SCE-7, at 20 through 22).

356 The Company noted that of the two wetlands to the west of the railroad, one was a natural wetland, and the other, located within the limits of the former gravel operation, was man-made (Exh. SCE-3, at III.2-4). The Company stated that both wetlands were subject to regulation by the Army Corps of Engineers and as such were not bound by the standard 100-foot buffer zone generally associated with natural wetlands (id.). The Company stated that no direct impacts to the natural wetland were expected (id.).

357 The Company stated that the man-made wetland would initially serve as a sedimentation basin during construction (Tr. 3, at 31). The Company further stated that, subsequently, the wetland would serve as a stormwater management basin with an overflow which would discharge over riprap approximately 50 feet from down-gradient wetland areas bordering the Taunton River (id.). The Company stated

(continued…)

With respect to the wetland bordering the Taunton River, the Company stated that a 400-foot retaining wall would be constructed to stabilize slopes in the buffer zone between the railroad bed and the edge of the wetland, and to avoid direct impacts to the wetland (Exh. SCE-3, at VI.1-7).[359] The Company indicated that approximately 73,000 square feet of buffer zone adjacent to that wetland would be altered by the proposed project (id.). The Company also indicated that installation of a water line to the proposed facility, construction of a new access road to the proposed TEC and improvements to the existing TMLP access road, would result in permanent encroachment of a total of 9300 square feet of wetland buffer zone at three other wetland locations (id. at VI.1-7 through VI.1-8; Exh. AG-2-13, att. at C-5).[360] The Company noted that the proposed sewer line extension from the TEC site to Railroad Avenue, would also affect on-site wetland buffer zones (Exh. AG-2-13, at C-6).

(…continued)
that such stormwater overflow would materialize only with storms of infrequent occurrence, i.e., 25-, 50- and 100-year storms, and would dissipate entirely by the time it reached down-gradient wetlands (id.).

358 The Company testified that the detention basin to be built for the proposed project at the man-made wetland would discharge to groundwater flowing into and recharging down-gradient wetlands (Tr. 3, at 42). The Company stated that this would essentially present no change from existing groundwater flow at the two wetlands (id.).

359 The Company stated that the retaining wall would be constructed with steel sheeting as a form along the base of the wall, and that it would eliminate the need to fill for side sloping and grading (Exh. SCE-3, at VI.1-7). The Company indicated that it chose to use steel sheeting for the retaining wall to avoid tree clearing and excavation for the gravel base and footings associated with a conventional concrete wall (id.). The Company stated that "weep holes" in the steel sheeting would ensure that the presence of the sheeting had no effect on groundwater and water flows (Tr. 3, at 33).

360 The Company stated however, that with the exception of two wetland areas bordering the Taunton River, there would be a relatively undisturbed buffer zone between the project construction activities and wetlands (Tr. 3, at 37). The Company also indicated that, by way of strengthening protection to the adjacent wetland area, it might plant trees within the buffer zone of a wetland near Railroad Avenue (id.).

The Company stated that it anticipated that there would be impacts to trees at the wetland bordering the Taunton River and within the buffer zone adjacent to one other wetland (Exh. SCE-3, at VI.1-7 through VI.1-9). The Company indicated that it would use a number of measures to mitigate the extent of tree clearing within wetlands and buffer zones (id.).[361]

With respect to floodplain impacts, the Company reported that, during construction of the cooling tower and the stormwater discharge outlet and retaining wall, floodplain alterations would occur which would permanently displace 250 cubic yards of flood storage volume (Exh. SCE-7, at 20-22). The Company emphasized, however, that it would construct a floodplain replacement area of greater size, i.e., 345 cubic feet, and within the same reach of the Taunton River to provide compensatory storage (id.; Tr. 3, at 38).[362]

With respect to impacts on wildlife habitat areas in buffer zones associated with wetlands bordering the Taunton River, the Company stated that it would restore a 7765 square-foot area which would be temporarily impacted by construction (Exh. AG-2-13, at C-8, C-9, D-10). The Company asserted that there would be no long-term adverse impacts on this area (id.). The Company reported that an additional 3500 square-foot wildlife habitat area would be permanently altered (id.). The Company asserted, however, that since the disturbed habitat would be less than 5000 square feet in area, the capacity of the habitat to provide important wildlife functions would continue unimpaired (id.).

The Company stated that water withdrawal for the proposed facility would have no adverse impacts on Taunton River streamflow, water quality, or ecology (Exh. SCE-5, at 4-

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361 The Company stated that, to minimize impacts on the wetland bordering the river, it would: locate the stormwater discharge outlet for the cooling tower of the proposed project outside the forested buffer zone; restrict tree clearing to areas along the slope of the railbed and in the vicinity of the cooling tower; and take precautions to maintain the forested buffer along the eastern edge of the cooling tower (Exh. SCE-3, at VI.1-8).

362 The Company stated that it was replacing eliminated floodplain for the Taunton Conservation Commission and in keeping with the WPA (Tr. 3, at 39).

2).[363] In support of its assertion that there would be no adverse impact on streamflow, the Company examined present and proposed water withdrawals from the Taunton River and compared the total, including those for the proposed project, against the safe yield of the Taunton River basin (id.).[364,365] In support of its claim that water withdrawals for the TEC would have no undue effect on Taunton River flow, the Company presented a flow duration curve using the state's safe yield figures (Exhs. EFSC-E-14; SCE-13, at 5).[366] The Company also provided evidence that the proposed water withdrawal from the Taunton River of 2.31 MGD (or 3.57 cfs) and 843.15 million gallons per year would be acceptable based on MDEP

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363 The Company stated that based upon the availability of adequate cooling water from the Taunton River and the minimal impacts associated with its use, SCE determined that water cooling would be the more advantageous than air cooling at the primary site (Exh. SCE-15, at 12; SCE Brief at 205).

364 The Company indicated that river flow data is generally obtained from the USGS and described in units of cubic feet per second ("cfs") (Exh. SCE-3, at VI.3-12). Data on existing and expected withdrawals for consumptive use were compiled by the MDEP and the Massachusetts Department of Environmental Management ("MDEM") based on information filed by water departments and industries and generic consumption use coefficients developed by USGS (id. at VI.3-14).

365 The Company reported that a 1991 MDEP determination set average daily stream flow at 140.1 cfs, minimum acceptable stream flow at 88 cfs, and the safe yield of the Taunton River basin at 52.1 cfs (Exh. SCE-5, at 4-2). The Company stated that all Taunton River withdrawals presently registered with MDEP, plus withdrawals for the proposed TEC, would total 38.3 cfs, or 13.8 cfs less than the state's determination of safe yield (id.).

366 The Company indicated that it compared existing and projected flow duration curves to a MDEM minimum stream flow estimate of approximately 88 cfs at the primary site intake location, or approximately 0.22 cfs per square mile of tributary area (Exhs. SCE-5, at VI.3-9 through VI.3-12; EFSC-E-14). The Company indicated that the probability of actual flow exceeding the minimum flow of 88 cfs currently is 93 percent, and that operation of the proposed TEC would reduce the exceedance probability by approximately one-half of one percent (Exh. EFSC-E-14, att. E-14-2).

water permit requirements (Exh. EFSC-RR-3).[367] The Company further stated that water withdrawals from the Taunton River for the proposed project would not directly alter any vegetated wetland area protected under the WPA (Exh. SCE-13, at 10). However, the Company presented results of its analysis indicating that water withdrawals for the proposed TEC would cause a minor upstream relocation of the "salt wedge"[368] of the Taunton River (Exhs. SCE-13, at 7; EFSC-E-18-1; Tr. 3, at 14 through 19). The Company noted that the extent of upstream relocation of the salt wedge as a result of water withdrawals from the TEC would be approximately 18 feet (Exh. SCE-13, at 7).[369] The Company asserted, however, that given the length and configuration of the Taunton River, there would be no adverse impact to river ecology due to salt wedge relocation associated with the TEC or all pending permits (Exh. AG-2-6).

With respect to dissolved oxygen ("DO"), the Company noted that the concentration of DO above the existing TMLP intake was higher than the Taunton River Class SB standard of a minimum of 5.0 milligrams per liter ("mg/l"), but that measurements varied throughout the year -- a low of 5.4 mg/l was recorded in August, with a high of 11.1 mg/l recorded in October (Exh. SCE-3, at VI.4-11, VI.4-13). The Company indicated that DO concentration of the TEC cooling tower blowdown would be approximately 7.1 mg/l before discharge (id.). The

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367 The permit amount would include a consumptive loss, i.e., water not returned as wastewater, of 1,400 gpm or 2,016,000 gpd (3.12 cfs) (Exh. SCE-3, at VI.4-2). Approximately 1,750 gpm would be withdrawn from the Taunton River for cooling water for the proposed project, of which 1,400 gpm will be consumed (id.). Other associated processes would produce approximately 38.5 gpm of wastewater of which 30 gpm would be consumed during ash pelletizing (id.). The remaining 8.5 gpm would be discharged to the Taunton River (id.).

368 The salt wedge refers to the mixing zone which occurs when fresh and saltwater meet (Exhs. SCE-13, at 7; Tr. 3, at 14 through 19). The mixing zone of the Taunton River is presently three miles below the proposed TEC project site (id.).

369 Movement of the salt wedge varies according to the extent of water withdrawals made from the Taunton River (Exh. SCE-13, at 7). The Company noted that, assuming permitting of all pending proposals for water withdrawal from the Taunton River including the TEC, salt wedge relocation could increase up to 420 feet (id.).

Company asserted that discharge of the blowdown was, therefore, likely to improve summertime DO levels in the Taunton River (id.).

With respect to eutrophication, the Company's witness testified that additional loadings from the TEC to the Taunton River would be minimal and would not result in any adverse conditions in the Taunton River or in waters of the connected Mount Hope and Narragansett Bay estuary system (Exh. SCE-19; Tr. 4, at 39-41). The Company reported that the existing nitrogen-to-phosphorus ratio in the Taunton River was 2:1, and indicated that this was significantly lower than the 7:1 nitrogen-to-phosphorus ratio at which increased plant growth and eutrophication occur (Exhs. EFSC-E-53; EFSC-E-17).

With respect to river temperature impacts, the Company asserted that recent temperature readings reinforced its expectation that temperatures at the mouth of the discharge canal would not exceed the NPDES permit maximum of 90°F (Exh. SCE-3, at VI.4-11).[370] The Company stated that 1975 temperature measurements showed temperatures at the confluence of the discharge channel and the Taunton River ranging from 77°F to 84.5°F (id. at VI.4-10). The Company indicated that a 1991 study conducted for SCE by Marine Research,

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370 The Company stated that maximum cooling tower blowdown temperature would be 90°F (Exh. SCE-3, at VI.4-11). Examining the thermal impact of the 350 gpm cooling tower blowdown on the Taunton River, the Company took into account the already existing impact on the river of discharge flows of 26,000 gpm from a 28 MW turbine generator which has provided electric power generation at TMLP since 1966 and which is designated as TMLP Unit 8 (id. at VI.4-1, VI.4-11). The average August peak temperature of discharge flows from TMLP Unit 8 is 87°F (id. at VI.4-11). The Company indicated that the resultant theoretical temperature increase of the mixed flow would be about .04°F, and that this amount would not significantly increase river temperature and/or cause river temperatures to exceed the NPDES permit maximum of 90°F (id.; Tr. 3, at 48 through 51). The Company also indicated that the average summer temperature of the Taunton River would be raised from 77°F to 77.04°F, which is below the MDEP maximum of 80°F (Exhs. SCE-15, at 6; SCE-3, at VI.4-5 through VI.4-7). Further, the Company stated that the EPA, in its preliminary draft NPDES permit, notes that the temperature increases anticipated in the Taunton River from the TEC are within acceptable limits (Exh. EFSC-E-41S at 7).

Inc. ("MRI") showed comparable temperatures of 72.3°F to 84.7°F measured just below the weir in the discharge channel in July, August and September (id.).

SCE also presented a mass and energy balance evaluation to predict the concentration of effluent constituents in the Taunton River after the TEC discharge and compared these concentrations with applicable water quality standards (Exhs. SCE-15, at 5-6; AG-2-7). The Company asserted that, although operation of the new cooling tower would concentrate chemical constituents of intake water approximately five-fold prior to discharge, resultant changes in stream concentrations of analyzed "marker" constituents would nonetheless be negligible (Exhs. SCE-3, at VI.4-2; SCE-15, att. R-3, at 42A; EFSC-E-17).[371,372]

The Company evaluated the potential impact of specific components of the discharge, including thermal characteristics, chlorine levels, discharge velocity, and DO levels on fisheries resources in the Taunton River (Exh. SCE-3, at VI.4-2). The Company stated that it had demonstrated that both thermal effects and effects of chlorine from the proposed discharge would be negligible (Tr. 3, at 48 through 51). With respect to DO, the Company indicated that the proposed discharge would increase DO at the discharge outfall during summer, potentially having a beneficial impact on fisheries resources (Exh. SCE-3, at VI.5-21 through VI.5-28). With respect to discharge velocity, the Company stated that no scouring of the river bottom was expected (id. at VI.5-28). In support of its assertion, the Company reported that the discharge

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371 SCE indicated that it had evaluated the proposed project effluent and designed a treatment system that would minimize effluent concentrations (Exhs. SCE-15, atts. R-1, R-2, R-3; AG-2-8; EFSC-E-16).

372 In response to specific concerns about chlorine discharge, the Company indicated that sodium bisulfate would be added to cooling tower makeup water for dechlorination if necessary (Exh. EFSC-E-16). The Company further reported that if the EPA and MDEP determined that chlorine applications for the existing TMLP and proposed TEC discharge streams could not overlap, it was prepared to accept additional restrictions (EFSC-E-16). The Company indicated, however, that after discharge into the Taunton River, the level of chlorine concentration would be less than .002 mg/l (Exh. SCE-3, at VI.4-13). The Company emphasized that this level would fall significantly below the rate allowed for discharge of residual chlorine under an existing NPDES permit to the TMLP (id.; Exhs. SCE-5, at 4-3 through 4-4; EFSC-RR-41S, at I.2).

volume of the proposed TEC outfall represented only a small (1.3 percent) increase over existing discharge volume at the same location (id.).

Finally, the Company evaluated the impact that the proposed TEC water withdrawal would have through impingement or entrainment on aquatic resources (Exh. SCE-13, at 8; Tr. 3, at 19 through 23). The Company noted that, as part of the water quality certification process under the jurisdiction of the EPA, a technical advisory committee ("TAC") had been formed to review the Company's plans for mitigation of impacts on aquatic species (Exhs. SCE-13, at 9; EFSC-E-18).[373] The Company explained that because (1) the same intake structure would be used for the proposed TEC as for the existing TMLP facility, and (2) the increase in intake velocity would be relatively small compared to existing intake velocity, no appreciable increase in the rate of impingement of fish or entrainment of ichthyoplankton, phytoplankton or microinvertebrates was anticipated (Exhs. SCE-3, at VI.5-21; SCE-13, at 7 through 9; EFSC-E-49).

(B) Analysis

The Siting Board notes that SCE has avoided primary site wetlands as much as possible in designing the proposed TEC and that it has, in addition, limited impacts to wetland buffer zones at the primary site. Further, the Company has described a full range of mitigation measures, including construction of floodplain replacement area, that will be used to minimize damage to wetland areas and buffers at the primary site.

In regard to water supply impacts on the Taunton River, the record indicates that the proposed TEC would utilize existing intake and discharge facilities. Further, the record demonstrates that the proposed intake of 2.31 MGD would conform with identified state permit

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373 The Company submitted copies of minutes of the TAC meetings, along with material from the Quarterly Report of MRI which conducted aquatic ecology studies for SCE in consultation with the TAC. Materials submitted provided results for the full period of the fisheries sampling program carried out by MRI from July, 1990 to August, 1991 and support the Company's claims of no significant impingement of acquatic species (Exhs. EFSC-E-18, EFSC-E-18, atts. 1, 2, 3, 4).

requirements, and proposed discharges would result in minimal impacts on water quality in the Taunton River. With respect to impacts on aquatic resources from operation of the proposed intake, the Siting Board notes the record supports the Company's assertions that such impacts would be minimal and that design measures reviewed by the TAC in conjunction with the EPA's water quality certification process will further ensure minimization of potential losses to aquatic resources from impingement or entrainment. Thus, the record supports the Company's position that adequate water is available for use from the Taunton River and that the impacts of such use would be minimal. Therefore, the Siting Board determines that such use of cooling water at this site is appropriate.

Accordingly, the Siting Board finds that the Company has established that the environmental impacts of the proposed facility at the primary site would be minimized with respect to wetlands and waterways.

iii. Water Supply and Wastewater

(A) Description

With regard to water use, the Company asserted that SCE's water use is acceptable and has been minimized (SCE Brief at 253 through 255). The Company indicated that its estimate of total water requirements for the proposed project, 2.31 MGD, represented a significant reduction in water demand from the Company's original estimate of 2.95 MGD

(Exh. SCE-5, at 2-2, 2-3).[374,375] The Company also indicated that reductions in water requirements were due to SCE's continuing optimization of water utilization requirements, including a project redesign to a single reheat boiler (id.).

The Company stated that the proposed project would withdraw 2,305,440 gpd of water from the Taunton River for cooling tower makeup and minor miscellaneous uses (Exhs. SCE-4, App. C at 3; SCE-5, at 2-3). Further, the Company stated that the TEC would use approximately 80,640 gpd of water from the City of Taunton for boiler feedwater and potable water (Exh. SCE-15, at 11).[376] The Company stated that it expected to meet this need with water from an existing 12-inch main located under Somerset Avenue (id.).[377] The Company stated that the capacity of the existing 12-inch main would be more than sufficient for the 60 gallons per minute ("gpm") water demand of the proposed project (id.).[378,379] The Company

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374 The Company stated that it is unaware whether the Taunton water permit will impose a limit on the amount of water SCE could receive from the City of Taunton (Tr. 3, at 8). However, the Company stated that under no circumstances would it expect to withdraw in excess of 2.31 MGD from the Taunton River, the maximum allowable consistent with applicable criteria under the Water Use Management Act (id.). Further, the Company stated that flows to the proposed project would be constrained by the size of the pipeline connection to the Taunton River (id. at 8 through 9).

375 The Company indicated that its water requirement estimate had gone through several iterations, including reduction from the original estimate of 2.95 MGD to an average of 2.54 MGD and later, with further design modifications, reduction to the Company's present estimate of 2.31 MGD (Exh. SCE-4, app. C at 1).

376 The Company stated that with the availability of water from the Taunton River for cooling water make-up and miscellaneous uses, SCE has reduced demand on the City of Taunton's potable water supply (SCE Brief at 261).

377 The Company stated that the TEC would tie into the Taunton water supply system either through an existing 6-inch service to the TMLP site or through an upgraded connection (Exh. SCE-3, at VI.14-2). The Company also stated that if an upgraded connection is necessary, the size and location of the service will be the subject of discussions with the Taunton Water Division (id.).

378 The Company stated that tests of the Taunton water supply system indicated an

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indicated that, in addition, on-site water storage would be established to attenuate peak demand and ensure that an adequate supply of potable water would be available at all times (Exh. EFSC-E-55).

The Company indicated that the only wastewater discharge to the Taunton sewer system by the proposed project would be sanitary sewage (Exh. SCE-3, at VI.14-3). The Company further indicated that wastewater flows to the Taunton sewer system would be relatively small and similar in quality to that of normal domestic wastewater (id. at VI.14-4).[380,381,382] The Company indicated that the proposed project would comply with the

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available capacity of 1280 gpm at a residual pressure of 40 pounds per square inch ("psi"), and 1605 gpm at a residual pressure of 20 psi (Exh. SCE-3, at VI.14-2). The Company stated that its estimates indicated that a fire flow requirement of 1500 gpm would be necessary to provide adequate water flow in the event of fire, given peak demand on the water supply system (id.). The Company stated that, with the fire flow requirement of 1500 gpm added to the 60 gpm for boiler feedwater and potable water, the maximum demand on the Taunton water supply system from the proposed TEC would be 1560 gpm, which is within the capacity of the existing system (id.).

379 In support of its statement, the Company submitted a copy of the May 7, 1991 Site Plan Review Decision of the Taunton Municipal Council ("Municipal Council") in which the Municipal Council noted that SCE's design for the proposed facility called for connections to the public water supply and public sewer systems (Exh. SCE-5, App. B). The Council determined that "[t]he planned capacities of public facilities such as water supply, sewage and drainage systems are adequate in the vicinity of the site to serve the proposed development…." (id.).

380 The Company indicated that as a result of the construction of the sewer connection for the proposed TEC, the sanitary wastewater from TMLP could be tied into the city sewer system, eliminating TMLP's use of an existing on-site system (Exh. SCE-3, at VI.14-4). In addition, SCE indicated it would extend the TEC sewer line to Railroad Avenue, allowing residences now using individual on-site systems to be tied into the city system (id.; Exh. SCE-5, App. B).

381 The Company indicated that, to conserve city water, its water conservation plan for the proposed TEC included such measures as the selection of low water consumption combustion technologies, recycling and reuse of process wastewater, recycling of
(continued…)

City of Taunton's Infiltration/Inflow program for wastewater reduction (id. at VI.14-3 through VI.14-4).

With respect to stormwater runoff, the Company stated that runoff from a storm of equal or lesser intensity than that of a 10-year-storm[383] would be conveyed to a stormwater management basin from which it would be slowly released to wetlands via infiltration over a period of 8 days (Exh. SCE-7, at 23). The Company indicated that, in addition to discharge by infiltration, runoff would also be released via an outlet discharge pipe to a riprapped discharge channel (id.). The Company stated that the 8-day settling period for suspended sediments would ensure the quality of the discharged water (id.). The Company stated that its stormwater management practices would ensure that runoff peak discharges from the primary site after development of the proposed TEC would be approximately the same as pre-development discharges (id.). The Company further stated that its stormwater management plan would meet all applicable Massachusetts regulations (id. at 25).

(B) Analysis

The Siting Board notes that the Company's redesign of the proposed facility during this proceeding to incorporate additional water conservation has resulted in significantly lowered projections of total water requirements, including cooling tower makeup, from an original estimate of 2.95 MGD to 2.31 MGD. The Siting Board also notes that the City of Taunton's

(…continued)
steam condensate, employee water awareness programs, leak detection efforts and the use of low flow toilets and plumbing fixtures (Exh. SCE-3, at VI.14-2).

382 The Company indicated that, due to the relatively small wastewater flows to the Taunton sewer system from the proposed facility, there were no plans to enlarge the Taunton Wastewater Treatment Facility peak design capacity of 12.5 MGD (Exh. EFSC-E-54). The Company noted, however, that the facility's peak capacity is sometimes attained during springtime wet weather conditions (id.).

383 The term "10-year storm" refers to the frequency with which a storm of a given intensity is likely to occur, i.e., once in ten years.

municipal water system would have sufficient capacity to meet the potable water requirements of the proposed TEC, and that the Company has included a full range of conservation measures to reduce potable water demand at the proposed facility. The Siting Board further notes that on-site storage of potable water for the proposed TEC will ease the drain on the City of Taunton's municipal water system during peak demand periods.

With respect to wastewater discharges, the Siting Board notes that the use of low flow plumbing fixtures to reduce wastewater flows to the Taunton sewer system, and the planned compliance of the proposed TEC with the City of Taunton's Infiltration/Inflow program for wastewater reduction, would contribute to minimizing impacts of the proposed facility on the municipal sewerage system.

The record demonstrates that demands that the proposed TEC would make on the Taunton River and City of Taunton water supply system at the primary site would be acceptable. The record further demonstrates that the Company has minimized impacts with respect to water supply and wastewater impacts of the proposed TEC at the primary site.

Accordingly, based on the foregoing, the Siting Board finds that the Company has established that the environmental impacts of the proposed TEC at the primary site would be minimized with respect to water supply and wastewater impacts.

iv. Land Use

(A) Description

SCE asserted that the location of the TEC at the primary site would be fully consistent with local land use objectives and compatible with the surrounding land use (Exh. SCE-13, at 15; Tr. 1, at 121). In addition, the Company indicated that the facility would not have significant adverse impacts on land use at the primary site, provided that suitable buffers are maintained and the facility's design meets MDEP noise guidelines (Exh. SCE-13, at 17).

The Company stated that the primary site consists of approximately 100 acres on which the current TMLP complex is located, of which approximately 25 acres located to the south and west would be the active primary site and would be leased by SCE for active facility development as part of the TEC (Exh. SCE-3, at III.2-1; Tr. 1, at 136). The active primary site, extending to the southern TMLP property line, consists of land that is presently undeveloped, but significantly disturbed, through prior use as a gravel removal operation (id.)

SCE indicated that the abutting land uses for the active primary site include land used by TMLP for power generation, riverine floodplain and wetland areas, abandoned agricultural land, and areas of residential use (Exh. SCE-13, at 16). The Company described the active primary site as industrial in nature, due to its proximity to the existing TMLP facility (Exh. SCE-1, at 8-43). In addition, the Company described the areas surrounding the entire 100-acre TMLP property as primarily residential in nature, coupled with some large areas of undeveloped land (Exh. SCE-3, at III.2-6). The Company indicated that approximately 550 residences are within a three-quarter-mile radius of the proposed facility site (Exh. EFSC-RR-14).

SCE indicated that the nearest areas of residential development are to the south and west of the active primary site (Exh. SCE-3, at III.2-6). SCE stated that medium density residential development is located along a section of Railroad Avenue which extends between Somerset Avenue (Route 138) and the Taunton River, and indicated that the roadway is located approximately 400 feet from the southern TMLP property boundary (id.; Exh. EFSC-RR-15; Tr. 1, at 137).[384] SCE indicated that approximately 12 homes and some vacant parcels are located on the north and south sides of that section of Railroad Avenue, and that two homes and three vacant parcels on the north side of Railroad Avenue directly abut the active primary site (Exhs. EFSC-3, EFSC-RR-15; Tr. 4, at 27). The Company stated that medium density residential development also is located to the west along Somerset Avenue, indicating that such

384 Two portions of the TMLP property extend to Railroad Avenue including (1) the southern end of the proposed on-site rail line on former rail ROW, and (2) a wooded area adjacent to the southwest corner of the active primary site (Exh. EFSC-RR-15). For the remainder of its length, the southern TMLP property line is abutted by parcels located on the north side of Railroad Avenue (Tr. 1, at 137). The rear of the nearest residence is located approximately 725 feet from the proposed location of the coal storage building (Exh. SCE-5, revised site plan).

development abuts portions of the TMLP property boundary on the east side of Somerset Avenue, approximately 1,000 feet from the active primary site, and extends to the west along South Street and an additional section of Railroad Avenue (Exhs. SCE-3, at III.2-6; EFSC-E-26; EFSC-3; EFSC-RR-15; Tr. 4, at 27). SCE noted, however, that a ridge is located on the TMLP property between the active primary site and the residential development to the west (Exh. SCE-3, at III.2-6).

The Company also identified residential areas to the northwest, north and east of the primary site, surrounding those portions of the TMLP property occupied by TMLP's existing facilities and TMLP's access road from Somerset Avenue. Specifically, SCE indicated that in an arc from the TMLP access road on the west to near the Taunton River on the north, at distances of between approximately 1,500 and 2,500 feet from the active primary site, residential development is located along Somerset Avenue, in nearby portions of the Silverwood Drive subdivision to the west, and in the vicinity of Sunhill Road, Boylston Street and Baker Road extending east from Somerset Avenue (id.; Exhs. EFSC-E-26; EFSC-3; EFSC-RR-15; Tr. 1, at 132 through 133; Tr. 3, at 77 through 80).[385,386] In the Town of Berkley on the opposite side of the Taunton River, the Company indicated that residences are located in newly subdivided areas approximately 1,500 feet northeast of the active primary site, as well as along Berkeley Street 2,500 feet east of the active primary site (Exhs. SCE-3, at III.2-6; EFSC-E-26; EFSC-3; EFSC-RR-15; EFSC-RR-74).[387]

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385 Mr. Mygatt estimated that the overall 106-unit Silverwood Drive subdivision is 60-70 percent constructed (Tr. 3, at 80).

386 The Company indicated that the City of Taunton plat maps show additional subdivided but undeveloped lots, with future roadways, for land located south and east of Boylston Street extending to the northern TMLP property boundary (Exh. EFSC-RR-15; Tr. 3, at 116 through 117). However, Mr. Mygatt estimated that the land had been platted for at least 15 years (Tr. 3, at 117).

387 The Company indicated that identified subdivision activity to the northeast included the 25-lot Townley Farm Estates subdivision, where three homes were built or are under construction, and the 22-lot Tide Meadows Drive subdivision, where subdivision road

(continued...)

SCE asserted that sufficient buffers exist between the primary site and residences in the vicinity (Exh. SCE-1, at 8-43). Mr. Mygatt stated that the buffer elements consist of: distance, together with the presence of the TMLP plant toward the northern site boundary; distance, and the presence of the Taunton River, riverine plain forest, and farmlands along the eastern boundary; and distance, vegetation, and ridge terrain toward the western boundary (Tr. 3, at 82 through 83).

The Company indicated that the southern boundary is relatively close and is not buffered by vegetation, and, therefore, the Company proposes to establish an on-site landscaped berm to provide an additional buffer to the south (id.). The Company indicated that the berm would be approximately 40-60 feet in elevation and adjoin with the ridge terrain of similar height located to the west of the active primary site (Exh. SCE-5, revised site plan).

The Company provided maps of existing land use for the areas surrounding the primary site for the TEC based on 1984 University of Massachusetts mapping data, updated to the end of 1991 through field work by SCE's consultant, HMM (Exh. EFSC-RR-50; Tr. 4, at 32). SCE indicated that the mapped land uses within one mile from the center of the active primary site consist of a combination of residential, commercial/industrial, and undeveloped uses (Tr. 1, at 126, 132). However, Mr. Mygatt acknowledged that the majority of the mapped industrial use areas are located one-half mile or more from the active primary site (Tr. 3, at 89). The Company indicated that, within one-half mile radius of the center of the active primary site, industrial land accounts for four percent of the land use, residential uses for 18 percent,[388] forest for 35 percent, agriculture for 25 percent, while other uses account for 18 percent (id.). Expanding the radius to one mile, the Company indicated that industrial land

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[387](…continued)
construction had begun (Exh. EFSC-RR-74).

[388] The Siting Board notes that the newly subdivided area located northeast of the primary site in the Town of Berkley is not reflected in SCE's residential category, but rather is designated predominantly as forest and agriculture (Exhs. EFSC-RR-50; EFSC-RR-74).

accounts for 6 percent of the land uses, residential uses for 22 percent, forest for 40 percent,[389] agriculture for 15 percent, while other uses account for 17 percent (id.).[390]

With respect to zoning, the Company stated that the majority of the active primary site is zoned Open Space/Conservation, but noted that the portion of the site to be traversed by the proposed access road is zoned Suburban Residential (Tr. 6, at 129).[391] Relative to the land surrounding the active primary site, the Company identified the zoning as Open Space/Conservation on the remaining portion of the TMLP site to the north, Suburban Residential to the north of the TMLP property, Suburban Residential to the south and west; and residential to the east of the Taunton River in the Town of Berkley (Exh. EFSC-RR-8).

SCE stated that the proposed facility has received City of Taunton Site Plan Review approval (Exh. EFSC-B-5-2). In its approval, the Municipal Council noted that due to the involvement of the TMLP in the project, including broad powers of oversight, control, and ownership options, the proposed project constitutes a municipal use which is an allowed use in any zoning district (id.).

In explaining the basis for the Site Plan Review approval, Mr. Roberts stated it was his understanding that planned private ownership and operation of the TEC does not preclude its classification as a municipal use for zoning purposes, and cited examples of other private concerns operating on similarly zoned city property, including private schools and use of a

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389 Mr. Mygatt acknowledged that there might be an occasional house scattered in land designated as forest, but stated that this would only encompass 10-20 homes within the one-mile radius (Tr. 4, at 33).

390 The Company also provided figures on land use groupings, whereby within a one-half mile radius the combination of commercial, industrial and mining comprised five percent; and within a one mile radius the percentage was nine percent (Exh. EFSC-RR-50).

391 According to The City of Taunton Zoning By-laws, the purpose of the Open Space/Conservation District is to establish and preserve areas for government facilities and open space (Exh. EFSC-RR-9). In addition, the purpose of the Suburban Residential District is to establish and preserve areas for residential development while maintaining the atmosphere of open space (id.).

contracted operator at the municipal sewerage plant (Tr. 6, at 132). Regarding the prospect of future sales of unsold TEC capacity, as well as planned regional dispatch of TEC output, to utilities other than TMLP, SCE noted that output from existing TMLP facilities, located in the same zoning district, currently is partially contracted and regionally dispatched to such other utilities (id. at 134 through 138).[392]

SCE indicated that it also has received a height variance and a special permit for location in a flood overlay district from the Taunton Zoning Board of Appeals ("Board of Appeals") (Exh. EFSC-B-5-2). Addressing the height of the various proposed structures on the site, the Board of Appeals stated that literal enforcement of the 40-foot height restriction would involve substantial hardship for the petitioner, and further that the site is not suitable for uses which would be allowed without such a variance (id.). In issuing the special permit, the Board of Appeals noted limited activity would occur in the flood overlay district (id.). SCE stated that the height variance and the special permit are both under judicial appeal, and that, therefore, the Company has petitioned the Department for a zoning exemption (Tr. 6, at 132).[393]

SCE asserted that the proposed TEC would not adversely affect property values in the vicinity of the primary site (Tr. 7, at 130 through 132).[394] In support of its position, SCE

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[392] SCE indicated that the existing TMLP capacity at the site is 135 MW, exceeding the current TMLP load of approximately 100 MW (Tr. 6, at 137). The Siting Board notes that, with the addition of the TEC, combined capacity at the site would be 285 MW.

[393] The Company stated that it applied for the exemption to expedite resolution of the appeals, which SCE believes would be a slow process if undertaken through the court system (Tr. 6, at 133). The zoning exemption request has been docketed as D.P.U. 91-214 and is pending before the Department.

[394] As a potential benefit for Railroad Avenue property owners, the Company indicated that, in conjunction with providing sanitary sewer connection for the proposed TEC at the primary site, it would extend a new sewer line to Railroad Avenue where residences currently rely on on-site septic disposal systems (Tr. 3, at 118). The Company cited the belief of local officials that there have been problems with failing on-site septic systems in the area, and noted that the $800 cost to homeowners for a sewer connection would compare favorably to the estimated $4,000 to $5,000 cost for

(continued…)

provided a 1992 property value analysis by a real estate company in Plymouth, Massachusetts concluding that the Pilgrim nuclear power plant in that community had not reduced nearby residential property values (Exh. EFSC-RR-71).[395] Mr. Roberts stated that the results of the analysis are consistent with positions held by utilities in general, namely that power plants have not adversely affected property values (Tr. 7, at 132). Mr. Roberts noted, however, that in the case of the Ocean State power project in Rhode Island, the project proponent developed a property value guarantee program prior to construction to address the concerns of property owners (Exh. EFSC-RR-48).[396]

SCE asserted that transmission access is available on site and that no new or expanded transmission ROW would be required (Exhs. SCE-1, at 8-43; SCE-13, at 15). With respect to fuel deliveries, SCE stated that the proposed project would require reactivation of a rail spur line extending 3.1 miles from the active Conrail line in downtown Taunton, to the primary site (Exh. SCE-3, at VI.10-2). Based on a review of land use and zoning maps provided by the Company, it is apparent that the spur line would traverse areas with a variety of land uses and zoning classifications (Exhs. EFSC-RR-8; EFSC-RR-10S). The Company indicated that reactivation of the spur line would provide rail access to the Weir industrial area, supporting state and local economic development policy (Exhs. SCE-1, at 4-48; WG-T-6A).

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[394](…continued)
replacement of a failing septic system (Exhs. HO-RR-46, HO-RR-70).

[395] The analysis, prepared in 1992 at SCE's request, cited five current listings of available properties, and 12 earlier listings of properties that resulted in sales from 1989 through 1991, all located approximately one-half mile to six miles from the Pilgrim plant (Exh. EFSC-RR-71). The analysis stated that there has never been any locational reduction in real estate value near the Pilgrim plant (id.).

[396] SCE stated that the program was expected to include: (1) a methodology to establish appraised value for purposes of guarantee; (2) a stipulated period for which the property owner must market the property before seeking guaranteed value; and (3) a limited period of program applicability following completion of the power plant (Tr. 7, at 130).

The Company indicated that installation of the TEC at the primary site would result in no potential historic impacts (Exh. SCE-3, at VI.8-2). The Company also asserted that the proposed TEC would not affect Blake Cemetery, which is less than one acre in size and located on the east side of the rail spur line at the TMLP northern property line (id. at VI.8-1; Exh. EFSC-RR-15).

Mr. Graban argued that the decision to proceed with a CFB facility at the primary site was made at the time of the TMLP RFP solicitation and award in Fall 1989, without opportunity for public input (Graban Brief at 3-2). He further asserted that the residents of Railroad Avenue are very interested and concerned about the value of their property (id. at 3-4).

(B) Analysis

The record indicates that, although the Company characterizes the existing land use in the vicinity of the primary site as a mixture of industrial, commercial, residential and agricultural, the immediately surrounding areas predominantly contain residential uses and residentially zoned undeveloped areas. Within a half-mile radius of the active primary site, industrial uses account for only four percent of the land use including the TMLP Cleary Substation.

Of particular concern for land use compatibility, the residences on Railroad Avenue would be in very close proximity to the proposed facility, directly abutting the active primary site.[397] Further, despite the Company's assertion that the area is already industrial based on the presence of TMLP's existing facility, the visual impact of that facility on Railroad Avenue is significantly buffered by the 1,500-foot separation and intervening tree growth.

The Siting Board previously has reviewed other generating facility proposals involving sites with limited or non-existent buffer from at least some residences. However, such reviews

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397 Among the facilities previously decided by the Siting Council, the proximity to residences along Railroad Avenue is matched only in the NEA Decision where residences were located 700 feet from the proposed stack. See, 16 DOMSC 335.

have concerned gas-fired facilities with stack heights of between one-quarter and two-thirds that of the proposed TEC stack, and similarly smaller scale requirements for other facility features such as boiler building size and on-site fuel delivery and storage space. Cabot Power Decision, DOMSB at 420; Altresco Lynn Decision, 2 DOMSB at 201; 1993 BECo Decision, 1 DOMSB at 130; Enron Decision, 23 DOMSC at 222; West Lynn Decision, 22 DOMSC at 104; MASSPOWER Decision, 20 DOMSC at 396; Altresco Pittsfield Decision, 17 DOMSC at 405; NEA Decision, 16 DOMSC at 403. In addition, most such previous reviews of proposed facilities with some residential buffer limitations have involved sites in areas that already are more clearly industrial than the area of the primary site in this review. BECo Decision, 1 DOMSB at 125; Enron Decision, 23 DOMSC at 222 through 223; Altresco Pittsfield Decision, 17 DOMSC at 405.

The record indicates that SCE would provide a landscaped berm that would provide an important buffer between proposed facility structures and most of the length of Railroad Avenue, including all but the eastern-most residences. For the proposed facility to be constructed at the primary site, the Siting Board agrees that the level of mitigation represented by such a berm is a necessary step to address the land use compatibility concern, particularly given the availability of fill material and the amenability of site topography to that approach. However, the use of a berm or similar screening measures cannot substitute for the buffer provided by a greater space separation with mature tree growth.

The Siting Board also notes that this is the first review of a generating facility that is proposed for a location that is not specifically zoned for industrial use. While the local zoning and site plan review approvals provide some basis for the Siting Board to review the compatibility of the proposed TEC with zoning at the primary site, SCE's ability to proceed still would depend on favorable resolution of the zoning appeal or favorable Department action on a zoning exemption.

In explaining its understanding of the basis for TEC's consistency with local zoning, SCE cites credible examples to claim that neither private ownership of TEC, nor generation dispatch practices that effectively allow exchanges of power between generating facility operators at the primary site and other utilities besides TMLP, necessarily precludes classification of the TEC as a municipal use. However, by expanding combined TMLP and TEC capacity at the primary site to 285 MW, the TEC would increase the likelihood of substantial net annual exports of power from the TMLP territory to other utility systems, rather than simply exchanges of power between the TMLP territory and other utility systems. In addition, the TEC includes a proposed CO_2 production facility -- a use that is clearly not consistent with TMLP's established electrical generation use at the primary site. SCE has not provided examples or other evidence that supports an interpretation of municipal use, for zoning purposes, which would clearly encompass either (1) production of electricity beyond TMLP's needs -- without recognizable limit -- or (2) production of CO_2.

The Siting Board takes into account the results, to date, of the City of Taunton's Site Plan Review Process and the Board of Appeals process, both of which address design features and safeguards to minimize incompatibility with land use, and recognizes that the landscaping berm and other measures help reduce noise impacts and visual impacts. As mentioned above, these measures are important steps, although they do not substitute for an adequate space buffer with mature vegetation. In addition, the issues mentioned above in regard to land use compatibility concerns for Railroad Avenue residents, including the relationship of the level of compatibility here to levels addressed in previous reviews, stem in large part from the overall scale of the proposed CFB facility. From the perspective of zoning consistency, it appears that issues again closely related to scale -- namely, the allowable extent of electrical generating capacity beyond TMLP's needs and the ability to include CO_2 production -- raise the greatest uncertainties as to SCE's position that the TEC either should or ultimately would be approved or exempted for zoning purposes.

Accordingly, in order to ensure that the proposed project is consistent with current zoning, the Siting Board requires the Company to provide evidence of either a D.P.U. zoning exemption approval or resolution of zoning appeals to the Company's advantage.

Finally, regarding SCE's position that power plants do not affect property values, SCE provided a property value analysis that considered experience with listed residential properties located between approximately one-half mile and six miles of the Pilgrim nuclear plant. Despite the conclusion in that analysis and SCE's reference to positions of utilities generally all claiming an absence of past property value effects, there is no basis to conclude that such positions reflect land use impact circumstances comparable to those that would exist on the Railroad Avenue side of the primary site at distances of as little as 725 feet from portions of the proposed project structures.

The combination of factors discussed above, including limited existing industrial character at Railroad Avenue, lack of a significant space buffer including mature vegetation between the proposed TEC and Railroad Avenue, and the scale of facility required for a CFB boiler, associated stack and associated solid fuel handling activities, indicate a significantly greater potential for land use impacts on several near-by properties than in previous generating facility reviews. We note that, as described above, the Company intends to construct a berm with plantings and in Section III.C.2.c, below we require the Company to develop plans for off-site tree planting in consultation with officials of the City and local residents to mitigate impacts to such properties. However, the Siting Board notes that even with such mitigation, land use impacts on the identified properties would still be significantly greater than in any prior generating facility review. The only other apparent means to further mitigate such impacts to the identified properties would be through a property value guarantee program or other compensation program -- an option identified, but not evaluated, by the Company.

Thus, SCE has failed to establish that the proposed TEC at the primary site would be consistent with current land use. Further, SCE has not evaluated or proposed implementation of the identified property value guarantee program or other method of compensation for potentially affected property owners, or established that such programs or compensation is inconsistent with cost minimization for the proposed project.

Accordingly, based on the foregoing, the Siting Board finds that the Company has not established that the environmental impacts of the proposed facility at the primary site would be minimized with respect to land use.

v. Visual

(A) Description

SCE asserted that it had thoroughly analyzed visual impacts of the proposed facility at the primary site (Exh. SCE-3, at VI.7-1 through VI.7-19). The Company provided profile photographs with overlays of the proposed facility from five representative vantage points which were chosen based on the number of people potentially impacted and/or the degree of impact at the receptor location (id. at VI.7-1).[398] The Company indicated that the number of receptor locations was later expanded in response to intervenor and Siting Council requests (Exhs. EFSC-E-28; EFSC-E-28S; EFSC-RR-43; WG-RR-2). SCE also noted that it had provided an updated analysis of visual impacts to reflect adjustments to the proposed TEC design and layout (Exh. EFSC-E-27).

The Company stated that, while the most visible element of the proposed TEC would be its 397-foot stack, the top of the 159-foot boiler building would also be visible from several receptors, and both the boiler building and the coal storage shed would be partially visible from the Railroad Avenue receptor (Exh. SCE-13, at 13 through 14; Tr. 3, at 61, 65). With regard to the visibility of the stack, SCE asserted that the appearance of the stack would be consistent with that of the existing TMLP generating facility (Tr. 3, at 63 through 65).[399] The Company reported that the visual impact of the proposed stack would be minimized as much as possible by tapering the stack, by building any ladders and platforms on the inside of the stack to avoid outer protuberances, and by making the concrete outer shell of the stack a neutral color (Exh. SCE-13, at 14; Tr. 3, at 64).

The Company indicated that it would provide a berm and landscaping to buffer the view of the proposed facility from Railroad Avenue and design the facade of the proposed

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398 The affected locations include residences, Route 138 and commercial receptors, such as restaurant facilities (Exh. SCE-3, at VI.7-1 through 7-2).

399 The Siting Board notes that from a number of vantage points, the significantly higher TEC stack would be more visible than either the existing TMLP facility stacks or the proposed single flue TMLP facility stack, which is designed to be 249 feet (Tr. 3, at 63).

facility to minimize visual impacts generally (Tr. 3, at 61). More specifically, the Company stated that it plans to shield Railroad Avenue from visual impacts with three types of mitigation: "berming," planting, and architectural treatment (Exh. SCE-3, at VI.7-14). With regard to the berm, the Company indicated that shaping would resemble that of a natural landform as much as possible, that it would blend into high ground to the west of the coal storage building, and that, overall, it would create a significant focal point in the mid-range (Exh. SCE-13, at 14). Planting, the second form of mitigation, would occur atop the berm and extend down its slopes, and would integrate conifers for year-round visual buffering with mixed deciduous species to blend with local vegetation (id.).[400] With regard to architectural treatment, the Company stated that it would utilize the services of a professional architect, landscape architect and/or environmental designer, with expertise in choosing color schemes that harmonize large industrial structures with the natural environment (id.).

With regard to balancing stack height and visual impacts, the Company indicated that, an earlier design of the proposed TEC was based on a GEP stack height of 350 feet, and at that time, the Company determined that a 300-foot stack, which is the shortest stack that could be permitted, would have no significant effect on visual impact (Exh. SCE-3, at VI.7-14). The Company also indicated that it had examined the relative effectiveness of ambient air quality control of both a 350-foot stack and a lower 300-foot stack (id.). The Company stated that its

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400 The Company stated that additional tree planting was proposed for mitigation of visual impacts at locations other than the on-site berm near Railroad Avenue (Exh. EFSC-E-61; Tr. 6, at 176 through 183). The Company also stated that the additional mitigation would fulfill conditions of the City of Taunton Site Plan Approval requiring (1) that SCE annually distribute a specified number of trees and shrubs, some to be used for screening views of the TEC, to local residents and to the City of Taunton, and (2) that SCE plant a 2-acre grove of 30 eastern white pine trees in the northwest portion of the TMLP property to screen views of the existing TMLP and proposed TEC facilities from Somerset Avenue residences (Exh. SCE-5, at 3-2, 3-4). The Company acknowledged that the effectiveness of the two-acre grove of trees for screening the nearest residences on Somerset Avenue would be reduced by the lower elevation of the planting area relative to that of the residences (Exh. EFSC-3; Tr. 6, at 180 through 181).

comparison indicated that increases in both ground-level SO_2 and ammonia concentrations would be significant with the shorter stack (id.).[401] The Company indicated that it ultimately chose a GEP stack height of 397 feet[402] because it would minimize concentrations of emissions at ground level caused by aerodynamic downwash (Exh. SCE-3, at VI.11-10 through VI.11-11).

(B) Analysis

As the record demonstrates, the most visible element of the proposed TEC would be the 397-foot stack for the boiler building. The top of the 159-foot high boiler building itself, in addition to portions of the coal storage shed, would also be visible from several vantage points around the proposed TEC at the primary site. The record shows that the Company has redesigned the proposed TEC to use a single reheat boiler and that the number of stacks needed for the proposed facility is thereby reduced to one. However, the redesign resulted in an increase in GEP stack height.[403]

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401 SCE found that concentrations of SO_2 would increase markedly and that ammonia concentrations would exceed the 24-hour average AAL (Exh. SCE-3, at VI.7-14).

402 SCE stated that the increase of GEP stack height to 397 feet was a result of the revision of the facility design to utilize a single reheat boiler rather than two non-reheat boilers as originally proposed (Exh. SCE-5, at 2-1 through 2-2). The Company asserted that although a lower stack would be expected to have unacceptable impacts on air concentrations, the lower stack would not be expected to enhance the proposed TEC's visual impact sufficiently to offset the increased air quality impacts that would result (SCE Brief at 279, n.112).

403 With respect to stack height, the record shows that a lower stack would have negative impacts on ambient air quality. The Siting Board notes that GEP stack height is defined by formula in Federal regulations (40 CFR Part 51.1) and serves to avoid the influence of building aerodynamic wakes on stack emissions. The Siting Board recognizes that, given the trade-off of increased ambient air quality impacts for lower visual impacts incumbent with use of a lower-height stack, GEP stack height would likely be required by MDEP.

Profile photographs and overlays of the proposed TEC demonstrate that the visual impact of the proposed TEC, particularly of the stack, would be noticeable at a range of locations not presently impacted by the existing TMLP facility. In addition, since the affected locations include areas with a lot of activity -- a state highway and commercial uses, such as restaurant facilities -- as well as recently developed residential areas in various directions from the primary site, the potential visual impact of the proposed TEC at the primary site may be substantial not only in terms of number of vantage points from which impacts are felt but also in terms of numbers of individuals affected.

The Siting Board notes that significant visual impacts have been identified in some previous reviews of generating facilities. However, based on its scale and largely non-industrial surroundings, the proposed facility at the primary site in the present case presents visual impacts of greater magnitude than those associated with facilities previously analyzed (See 1993 BECo Decision, 1 DOMSB at 130-131; Enron Decision, 23 DOMSC at 222-225; NEA Decision, 16 DOMSC at 403-405). The most significant visual impacts from recently analyzed gas-fired facilities involved stack heights, in general, ranging up to 200 feet and in one case up to 240 feet.[404] The Siting Board notes that in its previous review of a coal fired facility with dimensions similar to those of the present facility, the site was significantly buffered from residential area.[405]

The record demonstrates that in the present case, the Company is committed to construction of a landscaped berm and additional on-site tree planting for mitigation of visual impacts on surrounding areas, consistent with conditions of the Taunton Site Plan Approval. Specifically, the record shows that the Company would construct the berm to reduce the

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404 The stack heights involved in recent Siting Board cases include: (1) 240 feet (See Cabot Power Decision, 2 DOMSB at 420); (2) 199-200 feet (See, Altresco Lynn Decision, 2 DOMSB at 201); (3) 150 feet (See, West Lynn Decision, 22 DOMSC at 104); (4) 380 feet (See, EEC Decision, 22 DOMSC at 393).

405 In that review, there was a distance of 4,000 feet between the proposed facility and the nearest residence (EEC Decision, 22 DOMSC at 401). Further, this buffer area was largely wooded with mature vegetation (id.).

visibility of the TEC from Railroad Avenue, and plant a 2-acre grove of trees to screen views of Somerset Avenue residents. There is, however, insufficient information in the record to determine the effectiveness of planted trees and bushes in providing substantial and timely buffering for the proposed screened areas. In addition, the record fails to show that the Company pursued specific options for off-site tree planting to provide potentially more effective screening for proposed screened areas or elsewhere. Thus, while the Company has recognized, and made efforts to mitigate, visual impacts in the vicinity of Railroad Avenue to the south and Somerset Avenue to the west of the primary site, the record fails to demonstrate that impacts in such areas, as well as the unaddressed areas to the west, north and northeast, would be adequately mitigated.

Thus, the record demonstrates that, at the primary site, visual impacts of the proposed facility with proposed on-site mitigation may still be substantial, and therefore would be inadequately minimized. Accordingly, the Siting Board finds that the Company has not established that the environmental impacts of the proposed facility at the primary site would be minimized with respect to visual impacts.

vi. Noise

(A) Description

SCE asserted that the noise generated by operation of the proposed TEC would not adversely affect the surrounding community at the primary site (SCE Brief at 224). SCE further asserted that (1) noise from operation of the proposed facility would be in compliance with applicable MDEP standards limiting allowable increases in noise at residences and property lines during facility operations to ten dBA above ambient levels and prohibiting pure tone noise, and (2) noise emissions from Conrail locomotives would conform to Federal limits of 70 or 73 dBA, depending on date of manufacture, during expected periods of idling in the site vicinity (id. at 224, 225, 232). SCE asserted that the worst-case construction noise levels would be intermittent and temporary, and would be no higher than levels occasionally experienced in the area from time to time (Exh. EFSC-E-23).

SCE stated that, to be noticeable to people, an increase in average noise level generally must be larger than three dBA (Exh. EFSC-E-21). SCE indicated that the MDEP ten-dBA limit applies to changes in noise measured as the dBA level that is exceeded 90 percent of the time ("L_{90}") (Tr. 7, at 90 through 91). Mr. Keast asserted that, given that an L_{90} analysis reflects increases that will occur at most ten percent of the time, the MDEP ten-dBA limit is a conservative guideline (id. at 90).

In support of its position that the proposed TEC would have acceptable noise impacts, the Company provided analyses of ambient background noise levels and expected noise increases resulting from construction and operation of the proposed facility at the primary site (Exhs. EFSC-E-23, EFSC-E-23S, EFSC-E-57S, EFSC-RR-78). To establish existing background noise levels for its noise impact analysis, SCE provided measurements of daytime and nighttime noise obtained in 1990 or 1991 for each of 11 receptors, including seven residential receptors and four TMLP property line receptors located at distances of 800-3300 feet from the proposed TEC stack; SCE noted that the most distant residential receptor is located within 200 feet of the rail spur line (Exh. EFSC-E-57S).[406] SCE stated that principal sources of existing noise include traffic on Somerset Avenue (Route 138) and to a lesser extent Berkley Street, industrial operations such as the TMLP facility and the municipal sewerage facility, and residential area activity (id. at 7-1, 7-2).

To determine noise impacts from operation of the proposed facility at the primary site, SCE provided estimates of combined facility and background noise by receptor both for daytime periods, with and without noise contributions from coal delivery and ash pellet removal

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406 SCE developed measurements for four additional receptor locations, two representing earlier locations on the TMLP western property boundary prior to a recent acquisition expanding the boundary, and two representing residential receptors to the north and northeast of the active primary site (Exh. EFSC-E-57S at 7-2 through 7-4, 7-10). SCE indicated that it did not calculate facility noise impacts for the four receptors because other receptors were representative in demonstrating compliance (id.).

activities, which are expected one day per week, and for nighttime periods (id. at 7-66).[407,408] With respect to the residential receptor on Railroad Avenue, south of the active primary site, SCE provide two sets of daytime and nighttime noise impact estimates to represent normal and reduced levels of noise attenuation as a result of a proposed 60-foot elevation berm under varying meteorological conditions (id.).

The results of SCE's analysis indicate that, with facility operation and no on-site train activity, daytime L_{90} levels would increase by one to two dBA at residential receptors and by one to five dBA at property line receptors, but during periods of reduced berm attenuation[409] the L_{90} level at the Railroad Avenue residential receptor would increase by up to five dBA (id. at 7-66). The analysis further indicates that, with facility operation, nighttime L_{90} levels would increase by two to nine dBA at residential receptors and four to ten dBA at property line receptors, except that during periods of reduced berm attenuation the L_{90} level at the Railroad Avenue residential receptor would increase by up to ten dBA (id.)[410] The results show that the largest nighttime increases would occur at receptors located on or near the Taunton River away from more heavily travelled roads, including increases of ten dBA at the eastern property line,

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407 SCE indicated that its measurements reflected weekend, late fall (defoliate) conditions for all receptors, and for five of the residential receptors, also reflected other combinations of conditions, including weekday and summer (foliate) conditions, (Exh. EFSC-E-57S at 7-4).

408 SCE stated that the TMLP facility was operating intermittently during some daytime measurements but was not operating during nighttime measurements (Exh. EFSC-E-57S at 7-5).

409 Reduced berm attenuation under meteorological conditions occurs 25 percent of the time.

410 SCE's analysis indicates that, with facility operation but without train activities, combined background and facility daytime L_{90} levels would range from 39 to 45 dBA at residential receptors, and up to 46 dBA at property line receptors (Exh. EFSC-E-57S at 7-66). SCE's analysis indicates that, with facility operation, combined nighttime L_{90} levels would range from 36 to 41 dBA at residential receptors, and up to 46 dBA at property line receptors (id.).

seven-dBA at the Townley Farm Estates subdivision residential receptor, and nine dBA at the residential receptor at the end of Railroad Avenue (id.). With facility operation and on-site train activity, the Company's analysis shows L_{90} increases of from three to ten dBA at residential receptors and up to 10 dBA at property line receptors (id.). The Company indicated that it also had considered the effect of assuming a second southern property line receptor located east of the identified receptor in its analysis, specifically at the northeast corner of a vacant parcel immediately west of the proposed on-site tracks extending toward Railroad Avenue (Tr. 7, at 20 through 31, 50 through 52). The Company's witness, Mr. Keast, stated that operation of the proposed facility with on-site train activity would result in an L_{90} increase of 24 dBA at that property line location, but noted that if required, construction of a 20-foot high sound barrier extending south from the berm along the west of the track would reduce such noise increase to within the MDEP 10-dBA limit (id. at 52 through 53).[411]

SCE indicated that it also evaluated expected annual average noise levels at residential receptors, with and without facility operation, based on the EPA's recommendation of a maximum day-night noise level ("L_{dn}") of 55 dBA in residential areas to avoid undue interference with activity and annoyance (SCE Brief at 234, citing, Exh. SCE-10R at 3-4).[412] SCE identified four residential receptors where, based on averaging eight summer and late autumn measurements at each receptor, existing L_{dn} levels range from 54 to 63 dBA (Exh. EFSC-E-57S at 7-22, 7-23; Tr. 7, at 87). The Company indicated that, with operation of the proposed facility, the L_{dn} level would increase from 54 dBA to 55 dBA at one receptor, on

[411] SCE's analysis indicates that, with facility operation and train activities, combined background and facility daytime L_{90} levels would range from 45 to 49 dBA at residential receptors, and up to 51 dBA at property line receptors (Exh. EFSC-E-57S at 7-66). For the possible additional southern property line receptor adjacent to the tracks extending toward Railroad Avenue, Mr. Keast stated the combined L_{90} level would be 66 dBA (Tr. 7, at 52).

[412] SCE indicated that the EPA's L_{dn} indicator reflects the average sound level over a 24-hour period with a 10 dBA weighting factor added for a nine-hour nighttime period (Exh. SCE-10R, at 8; Tr. 7, at 82 through 83).

Railroad Avenue, but remain unchanged at the other three receptors, on Somerset Avenue, Boylston Street and Berkley Street (Tr. 7, at 87).[413]

The Company indicated that the residential receptor at Baker Road, 200 feet west of the rail spur line, was included to demonstrate compliance with the MDEP noise guideline with respect to noise impacts of idling Conrail locomotives one day per week (Exh. EFSC-E-57S). SCE indicated that, after the early morning arrival of the coal train, the locomotives would wait for the late evening return trip at a location approximately 1,400 feet north of Baker Road, 1,200 feet from the receptor (Exh. EFSC-RR-78). SCE's analysis showed that the proposed facility with train activity would increase the daytime L_{90} level from 41 dBA to 50 dBA at the Baker Road receptor, based on an estimated noise contribution from idling locomotives of 49 dBA at that receptor (Exh. EFSC-E-57S at 7-51, 7-66).

SCE indicated that, before identifying the proposed location for the idling locomotives, establishing compliance with the MDEP guideline at the Baker Road receptor, it had considered an area for idling locomotives located in a cut approximately 900 feet from the receptor but determined that use of such location would result in noise increases exceeding the MDEP guideline (Exh. EFSC-RR-78, with attachment). At the same time, SCE's witness, Mr. Keast,

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413 The Company indicated that the existing L_{dn} levels are 62 dBA, 57 dBA and 63 dBA at residential receptors on Somerset Avenue, Boylston Street and Berkley Street, respectively (Tr. 7, at 87). Although the Company did not provide a L_{dn} estimate for the Baker Road residential receptor, the Company's measurements show summer and late autumn average noise levels for that receptor that, on balance, are generally comparable to those for receptors at Railroad Avenue and Boylston Street -- locations for which the Company identified L_{dn} levels of 54 dBA and 57 dBA, respectively (Exh. EFSC-E-57S at 7-22, 7-23; Tr. 7, at 87). Regarding the remaining receptors, the Company provided late autumn noise measurements only for the two residential receptors located near the Taunton River, one at the end of Railroad Avenue and one in the Townley Farm Estates subdivision in Berkley, and for the four property line receptors (Exh. EFSC-E-57S at 7-11, 7-21 through 7-23). With operation of the proposed facility, SCE indicated that the L_{dn} level would increase from 46 dBA to 49 dBA at the end of Railroad Avenue and from 43 dBA to 48 dBA at Townley Estates subdivision, but that these higher levels would be still well below 55 dBA (Tr. 7, at 87).

acknowledged that additional residences are located in the area of an adjacent street north of Baker Road, and that SCE had not estimated noise impacts at such residences as part of its evaluation of either the currently proposed or earlier identified location for idling locomotives (Tr. 7, at 59 through 64).

With respect to construction noise, the Company provided estimates of long-term average noise at the nearest residence, located on Railroad Avenue 400 feet away from the nearest construction activity, including noise estimates with and without consideration of distance adjustments by construction phase and attenuation adjustments for the proposed berm which would be completed in an early construction phase (Exhs. SCE-5, at 4-12; EFSC-E-23). The Company estimated unadjusted average noise impacts of 60 to 71 dBA over the three-year construction period at the nearest residence, and noted that such noise impacts would decline to 50 to 61 dBA at residences on Somerset Avenue, 1,400 feet away (Exh. EFSC-5, at 4-12). During the first four months of construction, prior to completion of the berm, the Company estimated average noise impacts at the nearest residence of 66 dBA during ground clearing and 71 dBA during excavation and berm construction (Exh. EFSC-E-23). After completion of the berm, the Company estimated adjusted noise impacts at the nearest residence as follows: 49 dBA during the seven-month foundation construction phase, 56 dBA during the 15-month erection phase, and 60 dBA during the eight-month final construction phase (id.).

The Company asserted that its proposed facility design would incorporate substantial and expensive noise mitigation measures to minimize noise impacts from continuous sources and train-related activities (SCE Brief at 227, citing, Exh. SCE-3, at VI.12-20 through VI.12-23; Exh. SCE-E-57S at 7-19). Specifically, to mitigate continuous-source noise, the proposed facility would include: (1) a special muffler in the stack to address the induced draft fan exhaust; (2) heavy duty lagging for the induced draft fan housing and breeching; (3) a low-noise transformer or transformer barrier wall for the main transformer; (4) noise attenuating louvers for the ventilation openings in the turbine/boiler building; and (5) low-noise design for the cooling tower (SCE Brief at 227; Exh. SCE-E-57S at 7-19). To minimize noise from railcar loading and unloading, the proposed facility would include (1) a specially quieted switching engine or mechanical car indexer, and (2) acoustically lined entrances to the coal unloading shed (id.).

In response to Siting Board requests, the Company identified options to further mitigate noise impacts from continuous sources and train-related activities (Exhs. EFSC-RR-81, EFSC-E-69). With respect to continuous sources, SCE indicated that further noise mitigation, to address in particular estimated nighttime residential noise increases approaching ten dBA such as that at the receptor at the end of Railroad Avenue, would require measures to address various major noise contributors (Exh. EFSC-RR-81). SCE identified two options providing different levels of additional mitigation at the end of Railroad Avenue: (1) a six dBA reduction option, including full enclosure of the induced fan housing and breeching, a quieter transformer, increased wall weight for all sides of the turbine/boiler building, and increased length of the exhaust stack muffler; and (2) a three dBA reduction option, including the full enclosure of the induced fan housing and breeching and the quieter transformer as above, but limiting the increase in wall weight to two sides of the turbine/boiler building and providing a smaller increase in the length of the exhaust stack muffler (id.; Exh. EFSC-E-69).[414] With respect to train-related noise, SCE indicated that a noise barrier as high as 20 feet would be installed if required along the west side of the track extension from the berm to Railroad Avenue, and that a sound barrier also could be installed north of Baker Road to screen residences on the west side of the tracks from the proposed locomotive idling location (Exhs. EFSC-RR-81, EFSC-RR-87).[415]

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[414] SCE indicated that, if the four respective sources were addressed individually, complete elimination of noise from any one such source without further reducing noise from the other three sources would result in overall reductions of only one to 1.5 dBA (Exh. EFSC-RR-81).

[415] SCE stated that the precise dimensions and location of a sound wall extending from the berm toward Railroad Avenue, if required, would be determined during detailed design of the facility (Exh. EFSC-RR-80). SCE stated that a sound wall to screen the residential receptor at Baker Road would be impractical because a wall extending 1,200 feet along the full length of track from the receptor to the idling location would

(continued...)

SCE argued that the six-dBA reduction option would be costly, and not necessary given the consistency of the Company's proposed noise levels with the MDEP 10-dBA limit (SCE Brief at 230 through 231). SCE further argued that the three-dBA reduction option would be of minimal benefit because the three-dBA difference would be barely perceptible (id. at 231).[416]

(B) Analysis

In past decisions, the Siting Board has reviewed estimated noise impacts of proposed facilities for general consistency with applicable governmental requirements, including the MDEP's ten-dBA guideline. Cabot Power Decision, 2 DOMSB at 406-407; Altresco Lynn Decision, 2 DOMSB at 197; Altresco-Pittsfield Decision, 17 DOMSC at 401. In addition, the Siting Board has considered the significance of expected noise increases which, although lower than ten dBA, may adversely affect existing residences or other sensitive receptors such as schools. 1993 BECo Decision, 1 DOMSB at 104-106; Enron Decision, 23 DOMSC at 310-311; NEA Decision, 16 DOMSC at 402-403.

Here, SCE's noise analysis indicates that facility operation would result in nighttime L_{90} increases of seven to ten dBA at two residential receptors near the Taunton River, as well as the eastern property line receptor at the Taunton River. In addition, with reduced berm attenuation under meteorological conditions occurring 25 percent of the time, operation of the proposed facility would result in a nighttime L_{90} increase of up to 10 dBA at an additional residential receptor on Railroad Avenue. During the day, operation of the proposed facility

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[415](…continued)
be needed to break the line of sight (id.). The Siting Board notes that SCE failed to address possible benefits of a sound wall at the idling location for screening residences in the area of the adjacent street north of Baker Road (id.; see, Tr. 7, at 60 through 64).

[416] SCE stated that, if additional noise mitigation is required, SCE should be allowed the flexibility to design the most cost-effective approach for meeting such requirement (Exh. EFSC-E-69).

would result in continuous source L_{90} increases of five dBA or less at all receptors, but one day per week would result in train activity related L_{90} increases of eight to ten dBA at two residential receptors -- at Railroad Avenue and at Baker Road -- as well as at the northern and eastern property lines. Further, SCE admitted that, considering a possible southern property line receptor adjacent to the proposed on-site tracks extending toward Railroad Avenue, an L_{90} increase of as much as 24 dBA would result during periods of on-site train activity.

With respect to nighttime noise impacts, while estimated L_{90} increases at three receptors would approach the MDEP ten-dBA limit, the Company has maintained that such impacts are of no concern because L_{dn} levels would be well below the EPA's recommended residential area maximum of 55 dBA for the two receptors near the Taunton River, and at the 55 dBA maximum for the remaining receptor on Railroad Avenue. In a recent review in which the Siting Board limited L_{90} increases to no greater than five dBA, the Siting Board did cite concerns with an estimated L_{dn} level of 59 dBA at affected residential receptors -- a level clearly over the EPA 55 dBA maximum. 1993 BECo Decision, 1 DOMSB at 108, 109, 114.[417] However, in an earlier review in which the applicant calculated residential receptor noise impacts of up to 48 dBA and L_{dn} levels were not at issue, the Siting Council also raised concerns about a calculated maximum nighttime noise increase of seven dBA, citing the possibility of abutter complaints. NEA Decision, 16 DOMSC at 401-403.[418]

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417 Noise increases from operation of the previously reviewed Enron facility also were limited to no greater than four dBA, by terms of a municipal Special Permit. Enron Decision, 23 DOMSC at 207. In that review, maximum residential receptor L_{90} levels with facility operation were estimated as 52.0 dBA in the day and 50.8 dBA at night -- conditions noisier than those estimated by SCE for any of its TEC receptors and likely to be above the EPA recommended maximum L_{dn} of 55 dBA. Id. at 208.

418 The Siting Council found that the applicant's proposed noise levels in that review were acceptable, but in conjunction with its finding, the Siting Council (1) noted the applicant's assertion that the actual maximum noise increase would be at least five decibels less than the calculated increase, given that assumptions underlying the calculated increase were conservative, i.e., tending to overestimate actual noise levels, and (2) required that, for two years following start-up, the applicant monitor noise

(continued…)

With respect to daytime noise impacts, L_{90} increases generally would be five dBA or less, but would approach ten dBA at the Railroad Avenue and Baker Road residential receptors during periods of on-site train activity one day per week. The record indicates that the existing L_{dn} level is just within the EPA recommended maximum of 55 dBA at Railroad Avenue, and that, based on comparability with the Railroad Avenue and Boylston Street receptors, the L_{dn} level at the Baker Road receptor likely is near or slightly above 55 dBA. However, given that the Company did not provide a L_{dn} estimate for the Baker Road receptor, it is unclear how L_{dn} levels in the area would be affected by noise from idling locomotives.

The record further indicates that the Baker Road receptor may not adequately represent the noise impacts of idling locomotives in residential areas north of the receptor. Moreover, with respect to the southern property line receptor, the Company acknowledges that a possible alternate receptor location adjacent to the proposed on-site rail line extending south toward Railroad Avenue would result in a L_{90} increase of 24 dBA with facility operation during periods of on-site rail activity.

The record includes SCE's consideration of options that would further minimize noise impacts from both continuous sources and train-related activity. Such options would reduce noise increases that: (1) are well above the three-dBA threshold for noticeable noise;[419] (2) approach the MDEP ten-dBA limit; and (3) affect residential areas with existing or calculated noise levels that are near and possibly above the EPA-recommended maximum.

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[418](…continued)
impacts at the nearest residence and report to the Siting Council concerning any noise complaints and resolution of such complaints. NEA Decision, 16 DOMSC at 402, 403, 408. The Siting Board notes that no such complaints have been reported.

[419] The Company apparently relies on the recognized three-dBA threshold for noticeability of a noise increase to argue that the identified three-dBA reduction option would represent a barely perceptible difference from the Company's proposed noise levels. However, to say that a three-dBA increase would not be noticeable is not to say that the difference between a six-dBA increase and a nine-dBA increase, both of which are noticeable amounts of increase, would be barely perceptible or would not result in different levels of possible concern to residents.

However, SCE has not proposed to implement options to further mitigate noise impacts from continuous sources or train-related activity, citing cost and limited effectiveness. While claiming that, if required, it could provide a sound barrier for on-site rail tracks extending south toward Railroad Avenue, the Company has not proposed or provided a design for such a barrier. Finally, the Company has not proposed or provided a design for a sound barrier to further mitigate residential noise impacts from idling locomotives, citing cost and limited effectiveness.

Accordingly, the Siting Board finds that the Company has not established that the environmental impacts of the proposed facility at the primary site would be minimized with respect to noise.

vii. Transportation

(A) Description

In this section the Siting Board discusses the rail and vehicular transportation requirements of the proposed facility and their impacts on local traffic at the primary site.

The Company stated that it had considered a range of alternatives for transporting coal, including barging coal to Rhode Island and completing transportation to Taunton by rail or truck (Exh. EFSC-E-40).[420] The Company indicated that its preference for rail transportation of coal from mine mouth to the proposed facility as planned was based on the potential additional benefits to the City of Taunton of a working freight rail line in addition to the greater ease and lower expense of rail transportation for the proposed facility (id.; Exh. EFSC-RR-105). (See Section III.C.2.a.iv, above.)

With respect to rail traffic, the Company stated that it planned to deliver coal by rail to the proposed TEC once a week (Exh. SCE-3, at VI.10-2). The Company indicated that it planned to use one 80-car train with 4 diesel locomotives to bring coal to the proposed TEC

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420 The Company stated that it had also considered barging coal to the site, but had eliminated this option because of associated dredging requirements and the complex environmental impacts and permitting that dredging would entail (Exh. EFSC-E-40).

(id. at III.1-2). The Company stated that it also planned to remove pelletized ash by rail once per week (id. at III.1-3). The Company indicated that, to remove waste ash produced by the proposed facility, a Conrail local train would separately deliver 10 empty hopper cars each week for loading with pelletized ash, and that these cars would be coupled to the end of the empty coal delivery train for removal from the site (id.).

With respect to the route taken by the coal delivery train, the Company stated that trains would pass along existing Conrail lines from Selkirk, New York, near Albany, across Massachusetts along the Boston & Albany mainline, a section of Amtrak's northeast corridor, and two secondary track segments, to a currently unused 3.1 mile rail spur owned by TMLP and extending to the primary site (id. at VI.10-2).[421,422] The Company indicated that the secondary track sections include 42 grade crossings, including 12 in downtown Taunton, and that the TMLP rail spur includes 6 additional grade crossings (Exh. EFSB-RR-139, att. B). The Company also provided information on existing train traffic levels on the mainline and secondary track segments, indicating that the addition of train traffic to serve the proposed TEC

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421 The Siting Board notes that existing Conrail and Amtrak rail 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 rail traffic and related effects on communities along existing rail lines. See, Altresco-Lynn Decision, 2 DOMSB at 213; Boston Edison Decision, 1 DOMSB at 192 n.234.

422 The Company provided a more detailed description of its proposed coal delivery route as follows: trains would travel east, from Conrail's rail yard in Selkirk, New York, southwest of Albany, to Framingham, Massachusetts via the Boston & Albany mainline (Exh. SCE-3, at VI.10-2). From Framingham, trains would pass south-southeast along the Framingham secondary track and the Amtrak Northeast Corridor in Mansfield, Massachusetts to the Middleboro secondary track in North Attleboro (id.). Trains would continue east and then south on the Middleboro secondary track onto a reconstructed industrial siding, proceeding from this point 3.1 miles to the coal unloading shed at the proposed facility (id.).

would represent a small change proportional to existing traffic on the mainline segments, but a more significant change on the secondary line segments (Exh. EFSB-AER-7).[423]

The Company stated that the train would arrive at about 6:30 a.m. and leave on the same day at about 9:45 p.m. (Exh. SCE-3, at VI.9-20, VI.10-4). The Company indicated that it had considered a broad range of alternatives to its proposed rail schedule, including weekend and midday delivery and departure times.

The Company stated that, in order to assess alternatives, it had obtained detailed information on Conrail and Amtrak policies, scheduling and operations (Exhs. EFSC-E-59; EFSC-E-65; EFSC-RR-83; EFSC-RR-84; EFSC-RR-85).[424] The Company asserted that schedule changes for midday passage of trains through Taunton could not be accommodated by Conrail and Amtrak (Exhs. EFSC-E-59; EFSC-E-65; EFSC-RR-85). The Company, in addition, presented a letter from the City of Taunton indicating the preference of the City's administration for early morning and late evening passage of coal trains (Exh. EFSC-RR-86).

The Company stated that it had identified local traffic patterns at key rail route intersections in Taunton (Exh. SCE-3, at VI.9-20; EFSC-E-66).[425] The Company indicated that, for an 80-car coal train with a posted train speed of 10 mph, maximum street blockage would be six minutes (Exh. SCE-3, at VI.9-20).

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423 The Company indicated that approximately 24 freight trains per day traverse the Boston & Albany/Conrail Mainline west of Framingham (Exh. EFSB-AER-7). The Company further indicated that the Framingham secondary line is served by two freight trains daily, out and return, and that the Middleboro secondary line is served by one freight train daily, out and return (id.; Exhs. EFSC-E-64; EFSB-RR-162).

424 In connection with its evaluation of scheduling alternatives, the Company stated that it had considered, in conjunction with Conrail, using rail sidings for train layovers, stopping for specified periods along the main tracks, and altering the timing of passage along the Amtrack corridor (Exhs. EFSC-E-59; EFSC-E-65; EFSC-RR-83; EFSC-RR-84; EFSC-RR-85).

425 In response to a request from Siting Board staff, the Company provided traffic counts for 30-minute intervals at five key intersections including Weir Street, Somerset Avenue (Route 138), Winthrop Street (Route 44), Oak Street (Taunton Mall) and Tremont Street (Route 140) (Exhs. EFSC-RR-137; SCE-3, at VI.9-20).

In order to mitigate adverse impacts on emergency vehicle traffic, the Company stated it would provide for placement of an ambulance on the opposite side of the track from the ambulance dispatch location during train passages (Exh. SCE-5, app. B at 5). In addition, the Company stated it would publish the schedule of train arrivals and departures and provide up-to-date copies of such schedule to local officials and emergency personnel (id.).[426]

Mr. Graban argued that passage of the coal train as planned would have an adverse effect on vehicular traffic in downtown Taunton, particularly at the Tremont, Washington, and Oak Street railroad crossings (Exh. WG-T-2A; Graban Brief at 1-1 through 1-2). He further argued that options such as grade separation at principal crossings, or in the alternative, a new fire, police, rescue and ambulance station, be implemented by SCE and Conrail to mitigate coal train passage impacts (Graban Brief at 1-2A, 1-3, 1-4, 1-4A, 1-4B).

With respect to vehicular traffic impacts, the Company stated that an access road to the TEC facility would be constructed at the existing TMLP access road off Route 138.[427] The Company stated that it had undertaken a traffic impact study which evaluated the impact of peak construction and commencement of operations at the facility relative to existing conditions (Exh. SCE-3, at VI.9-1 through VI.9-22).[428] The Company asserted that the results of the study

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[426] The findings stated in the Site Plan Review Decision of the Municipal Council dated May 7, 1991 requires the company to take such mitigation measures relative to the placement of the ambulance and providing the train schedules (Exh. SCE-5, App. B at 5).

[427] The Company indicated that, as a result of discussions with staff of the Massachusetts Highway Department, it planned to replace the existing TMLP access road with separate but adjacent access roads for the proposed TEC and TMLP's existing plant (Exh. SCE-3, at VI.9-2).

[428] The Company indicated that its study measured the level of service ("LOS") at a given intersection (Exh. SCE-3, at VI.9-5). The Company stated that LOS refers to the quality of traffic flow along roadways and at intersections and is described in terms of LOS A through F, where LOS A represents the best possible conditions, LOS D represents the lowest acceptable operating conditions, and LOS F represents forced-flow, or failing conditions (id.).

indicated that traffic during construction and during later operation of the proposed facility would have no significant impact on Route 138 traffic (id. at VI.9-7; SCE Brief at 281).[429,430]

Finally, the Company identified possible road routes from area highways to the Route 138 entrance for the proposed TEC, including routes extending through or near the downtown Taunton area (Tr. 7, at 135). The Company stated that, in response to concerns about truck traffic through Taunton Square, a route avoiding the Taunton Square area could be identified (id.).

(B) Analysis

With respect to impacts from rail traffic, the Siting Board notes that the Company has examined a broad range of scheduling possibilities in connection with a single train rail delivery to the proposed TEC at the primary site. Although the Company's present plan calls for trains to avoid rush hour traffic, the Siting Board notes that the planned hours of train movement may pose some nuisance, for example, to commuters at the early end of the morning rush hour or to those leaving local shopping malls when they close in the evening. Nonetheless, local officials supported the identified schedule, and any rescheduling to further minimize traffic impacts could cause late-night or early-morning noise disturbances for residential abutters.

The Siting Board also notes that the Company expects the coal train would use grade level crossings to travel through the center of Taunton as well as other locations along the secondary track segments of the overall rail route. As evidenced by the findings of the

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429 The Company indicated that, during peak construction of the proposed facility, at the intersection of Route 138 and the TEC access road, the p.m. peak hour LOS for vehicles leaving the site would be D (Exh. SCE-3, at VI.9-7; SCE Brief at 281). The Company indicated that after the proposed TEC commenced operations, the p.m. peak hour LOS for vehicles at the same intersection would be C (id.). Because the above-noted TEC access road does not now exist, no LOS is available for current conditions at the referenced intersection.

430 The Company stated that it would use a police officer to control traffic at the intersection of the TMLP access road and Route 138 during peak construction (Exh. SCE-3, at VI.9-1).

Municipal Council concerning placement of an ambulance on the opposite side of the track from the dispatch location, such train passage can interfere generally with movement of safety and emergency vehicles and equipment at grade level crossings. The Siting Board notes that the placement of an emergency vehicle on the opposite side of the track does not address the possibility of a delay when an emergency vehicle (i.e., an ambulance carrying an injured person), needs to reach a specific destination just as the train is entering the street crossing. In such cases, a delay caused by either the train going through the street crossing or the emergency vehicle taking a longer alternative route, may have serious consequences. The Siting Board also notes that G.L. c. 160, § 151 raises concerns relative to the obstruction of a public way by a railroad for more than five minutes at one time.[431]

Thus, with respect to impacts of rail transportation to and from the proposed TEC at the primary site, the record identifies a level of impacts from routing of rail transport through built-up portions of Taunton which raises concern. The option of grade separation improvements has been raised by Mr. Graban, although the record does not include detailed analysis of specific improvements and related benefits. While use of existing crossings is clearly less costly and less complicated in the short run than constructing grade separations or bypasses to grade level crossings, rail improvements may be warranted in the long run, particularly if upgrading rail facilities for freight leads to the increased industrial use of rail that the City of Taunton anticipates and encourages. Further, the record contains no information as to whether the Company considered alternatives to a six minute grade crossing -- e.g., a 40-car

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431 G.L. C. 160, §151 states, in part:

> A railroad corporation, or receiver or assignee thereof, or its servant or agent, shall not wilfully or negligently obstruct or unnecessarily or unreasonably use or occupy a public way, or in any case wilfully obstruct, use or occupy it with cars or engines for more than five minutes at one time; and if a public way has been thus used or occupied with cars or engines, the railroad corporation, or receiver or assignee thereof, shall not again use or occupy it with the cars or engines of a freight train, until a sufficient time, not less than three minutes, has been allowed for the passage across the railroad of such travellers as were ready and waiting to cross when the former occupation ceased.

train to provide coal to the proposed TEC twice per week as opposed to one 80-car train per week. The Siting Board notes that such alternatives could help to minimize the traffic impacts due to rail transport to the primary site.

The Siting Board also notes that, for the most part, rail transportation to and from the primary site at the proposed TEC may have impacts in other communities along the rail route, particularly the secondary track segments between Framingham and Taunton. The Siting Board notes that concerns raised in Taunton vis-a-vis increased rail traffic may be equally applicable in such other communities, and warrant consultation with local officials and the public similar to that undertaken in Taunton. The Siting Board notes that the same rail route proposed to serve the TEC project would be used for delivery of coal via train to the site of a generating facility previously approved by the Siting Board. EEC Decision, 22 DOMSC at 188; EEC (remand) Decision, 1 DOMSB at 213.

Given the potential for community concerns with the increase in the extent of train traffic -- reflected both in the large size of trains and in their greater frequency -- along the Framingham and Middleboro secondary lines, the Siting Board encourages SCE, in cooperation with Conrail, to consult with local officials and the public in such communities prior to any commencement of train operations for the proposed TEC facility.

With respect to increased vehicular traffic due to construction and subsequent operation of the proposed TEC at the primary site, the record demonstrates that the Company has worked with the appropriate public authorities to help minimize traffic impacts. The Siting Board notes that implementation of the identified design and operating measures at the Route 138 entrance, and truck routing to avoid Taunton Square as appropriate, would be necessary to help minimize the impacts on road traffic at the primary site.

Accordingly, based on the foregoing, the Siting Board finds that the Company has not established that the environmental impacts of the proposed facility at the primary site would be minimized with respect to impacts from rail traffic, and has established that environmental impacts of the proposed facility at the primary site would be minimized with respect to impacts from vehicular traffic.

viii. Solid Wastes

(A) Description

SCE indicated that combustion of coal in the proposed TEC would generate ash consisting of: (1) impurities in the coal (primarily inorganic compounds such as silica, alumina, and iron oxides); (2) gypsum, i.e., calcium sulfate (the reaction product of limestone and sulfur); and (3) unreacted or uncombusted materials (e.g., carbon, limestone, and minor impurities in the limestone used to control SO_2 emissions from the CFB) (Exh. SCE-3, at III.1-6).

The Company stated that based on fuel requirements for the TEC of 455,338 tons of coal annually, the operation of the proposed facility would generate 77,000 tons of solid waste (ash) per year (Exh. SCE-23, at 17). In calculating annual ash generation, SCE stated it assumed: (1) 7 percent ash in the coal; (2) a lime injection rate of 2.0 moles of calcium per mole of sulfur in the fuel; (3) 1.6 percent sulfur in the fuel; (4) 90 percent removal of SO_2; and, (5) 100 percent capture of ash in the boiler and fabric filter (Exh. SCE-23, at 17).

The Company stated that ash removed from the CFB as bottom ash and as flyash would be pneumatically conveyed to the main ash storage silo, which would have a 2-day storage capacity (Exh. SCE-3, at III.1-6).[432] SCE indicated that the ash would thereafter move by conveyor belt to an ash pelletizing plant, where (1) a treated wastewater spray would combine with excess limestone in the ash to convert the ash to a cement-like material for pelletizing, and (2) the "setting" ash would then be pelletized by tumbling in a drum (id. at III.1-7).[433] SCE indicated that, after pelletizing, the ash would go by mechanical conveyor through a dryer to an over-the-track, load-out silo, and from the silo to empty coal cars on the same day that coal was delivered and unloaded (id. at III.1-7; Exh. SCE-5, at 2-4).

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432 The Company further reported that the conveying air would be separated from the ash in cyclones and then exhausted through fabric filters for control of dust (Exh. SCE-3, at III.1-6).

433 The Company stated that redundant capabilities would be available for storage of ash and ash pellets, i.e., pellet storage could be utilized for ash storage, or ash could be loaded into rail cars and removed from the site (Exh. SCE-5, at 5-128).

With regard to disposal of ash, SCE stated that it anticipated that, as a requirement of a final coal supply contract, the ash would be returned to the coal supplier for disposal at a licensed out-of-state site (Exhs. EFSC-E-5; EFSC-E-36). SCE stated that it was also considering the potential for disposal of ash in non-pelletized form (Exhs. EFSC-E-6; SCE-5, at 2-5, 5-130). Noting that ash has been used commercially elsewhere, the Company further stated that it was interested in finding a commercial use for the ash in lieu of disposal (Exhs. EFSC-RR-55; SCE-5, at 5-130).[434] SCE indicated that if a commercial use for the ash were found, the ultimate disposition of the ash might be in a non-coal producing region, including New England (Exh. EFSC-E-5; EFSC-E-6).[435] The Company further stated that in no instance would disposal take place in New England (Exh. EFSC-E-5). The Company testified that the most likely use of the ash would be for mine reclamation to neutralize the acidity of mine wastewater (Exh. EFSC-E-5; Tr. 5, at 62 through 70).

(B) Analysis

The record indicates that the operation of the proposed facility would generate a significant amount of solid waste in the form of ash and that the Company would incorporate a number of ash control technologies into the design of the proposed TEC at the primary site. The record further documents that the Company has explored, and continues to seek, a commercially viable, environmentally benign use for both pelletized and non-pelletized ash from the proposed facility at the primary site. However, although the Company anticipates that its ultimate coal supplier will be contracted to remove ash from the proposed facility for out-of-

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434 The Company indicated, however, that to date it was unaware of a commercial use which would not increase ash disposal costs (Exh. EFSC-RR-55). The Company asserted that if ash from the proposed TEC is not pelletized, it will be transported from the proposed TEC site by rail in sealed pneumatic hopper cars (Exh. SCE-5, at 2-5).

435 The Company stated, however, that to date it had found no acceptable commercial user for ash from the proposed project (Exh. EFSC-E-6). SCE stated that the search for an acceptable commercial user for the ash was ongoing, and that the Company has had discussions with the City of Taunton Department of Public Works regarding the feasibility of mixing ash from the proposed TEC with municipal sewage sludge (id.).

state disposal, a signed coal supply contract has not been provided.[436] Thus, the record lacks documentation of the Company's ultimate arrangement for removal and disposal of solid waste from the proposed TEC at the primary site. Therefore, the Siting Board requires SCE to submit either (1) a signed agreement for the removal of ash, which includes provisions to ensure safe and environmentally acceptable removal thereof, or (2) a signed coal supply contract, which includes specific provisions to ensure safe and environmentally acceptable removal of the ash. If SCE complies with either portion of the condition regarding solid waste removal, the Company would be able to ensure that the environmental impacts of the proposed facility at the primary site would be minimized with respect to solid waste.

Based on the foregoing, the Siting Board finds that, upon compliance with the condition to provide a signed contract for the acceptable removal of ash, as stipulated above, the Company will have established that the environmental impacts of the proposed facility at the primary site would be minimized with respect to solid waste.

ix. Safety

(A) Description

The Company addressed concerns related to the storage and use of certain chemicals at the proposed facility. The Company indicated that particular care would be required to ensure the safe use and on-site storage of such chemicals (Exh. SCE-14, at 4 through 5).[437] The

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436 The Siting Board notes that if the Company's ultimate coal supplier is contracted for ash removal, ultimate use of the ash would fall outside the purview of the Siting Board and would instead be determined by the coal supplier. The Siting Board, also notes, however, that it is within its mandate to ensure that any ash generated by the proposed facility is removed in a safe and appropriate manner. See, EEC Decision, 22 DOMSC at 305.

437 The Company indicated that as part of final design preparations for the proposed TEC, it would submit a Spill Prevention Control and Countermeasure Plan, as required, to the local fire department, MDEP, and the local authority for emergency planning (Tr. 6, at 3). The Company stated that such a plan would be submitted with sufficient time to ensure its approval prior to the start of operations of the proposed facility (id.). The (continued…)

Company indicated that all chemical delivery, unloading, storage, transfer and usage at the proposed TEC would take place in designated areas engineered to contain and treat potential spills (id.). The Company further indicated that (1) spills occurring inside the plant would be routed through a floor drain system into a waste equalization tank, mixing with other flows entering the tank, after which they would be treated and discharged with plant effluent, and (2) oil spills would be captured via a water/oil separator, and any transformer leaks would either be absorbed by gravel cover or trapped by a closed drain in the transformer yard (Tr. 6, at 54 through 55). In addition, the Company stated that, as a CFB, the proposed TEC would not require the finely-ground coal necessary for a conventional boiler and would therefore limit the risk of coal dust explosion by controlling the generation of coal dust particles (id. at 4).

The Company stated that, for on-site bulk storage of sulfuric acid solution and liquid caustic soda solution, two 5000 gallon tanks would be used -- an outdoor tank for the sulfuric acid solution and an indoor tank for the liquid caustic solution to prevent freezing (id. at 5). As a precautionary measure against tank spills, the Company indicated that each tank would be surrounded by a concrete containment structure with a volume in excess of 5000 gallons and a manual pump to transfer spill material for reuse or removal (id.). The Company stated that, as an additional precaution, coarse limestone would partially fill the diked area surrounding the sulfuric acid solution storage tank as a neutralizing agent in case of an accidental spill (Tr. 5, at 232 through 233).

The Company stated that, with respect to the relative safety of using ammonia or urea with the proposed SNCR system for control of NOx emissions, ammonia would pose a greater

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(…continued)

Company further stated that all plant operating procedures would be designed in accordance with Best Management Practices as required by federal regulations (Exh. SCE-14, at 5). The Company also stated that the proposed facility would be designed, constructed, and operated in compliance with all regulations for employee safety promulgated by the Occupational Safety and Health Administration of the Federal Government (id. at 6; Exh. SCE-5, at 5-130).

storage hazard than urea (Tr. 2, at 8).[438] The Company presented a worst-case analysis of consequences of a release of aqueous ammonia stored at the primary site (Exh. SCE-8, att. B-2). The Company stated that its analysis indicated that even for a worst-case scenario with conservative assumptions as to the size of the spill and coincident weather conditions, off-site ambient concentrations would not exceed the recognized hazard threshold of 500 ppm (id. at 2).[439] The Company noted that an examination of MDEP records for the previous five years showed no ammonia spill accidents from fixed tanks or from unloading activities related to ammonia storage reported to MDEP during that time (Exh. EFSC-RR-22).[440]

The Company stated that the impact of a urea spill would be less than that of an ammonia spill, but that it could not quantify impacts because no assessment on the consequences of a urea spill had been done (Tr. 2, at 9). The Company indicated that its preference for ammonia over urea was based (1) on the fact that data was available on operating similar facilities with ammonia, but not with urea, and (2) the apparent greater cost of using urea (Tr. 6, at 24-27). The Company indicated that, while it felt that its ultimate choice would likely be

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438 The Company stated that the Immediately Dangerous to Life and Health ("IDLH") threshold, a limit used for ammonia release toxicity calculations based on a 30-minute exposure period, is 500 parts per million ("ppm") (Exh. EFSC-RR-21).

439 The Company stated that concentrations of dispersed ammonia vapor would diminish with increasing distance from the point of ammonia release, with concentrations reduced to the 500 ppm IDLH threshold at ground-level at a distance from the release point of 1083 feet (Exh. SCE-8, att. B-2, at 1 through 4). The Company based its estimate of a scenario in which one ammonia tank totally failed and instantaneously released its entire contents into the surrounding diked area (id.). The Company indicated that distance to the nearest property boundary from the point of ammonia release would be 1200 feet away, 117 feet beyond the distance at which ammonia vapor concentrations would equal or drop below the IDLH threshold (id.). The Company asserted that, on the basis of its modeling results, no off-site impacts of an ammonia spill would exceed the 500 ppm IDLH exposure limit (id.).

440 The Company also noted that, according to the Federal Emergency Management Agency, the general failure rate for single walled storage tanks per year is .0004 (Exh. EFSC-RR-22).

ammonia, it was still considering the use of urea (Tr. 6, at 28). See Sections III.C.2.a.i, above, and III.C.2.b, below.

To ensure safe use and storage of aqueous ammonia in connection with the reduction of NOx emissions, the Company indicated that liquid ammonia would be stored in three 25,000 gallon tanks (Tr. 6, at 19). The Company stated that one large concrete containment dike would surround the three tanks and would have a holding capacity in excess of the combined capacity of the three storage tanks (id. at 21; Exh. AG-2-9).[441]

(B) Analysis

The Siting Board notes that the CFB design of the proposed facility, and proposed coal handling measures, would limit the risk of coal dust explosion. The Siting Board further notes that design of the proposed facility would incorporate measures to avert spills of hazardous materials and to contain any such accidental spills. In addition, the Siting Board notes that the Company has developed a comprehensive program to address prevention and containment of spills involving hazardous materials.

With respect to safety concerns associated with the use of ammonia to assist in the control of NOx emissions, the record shows that consequences of an ammonia spill, conservatively analyzed, are likely to be within allowable limits. In addition, the record shows that the incidence of ammonia spill accidents, nationally and in Massachusetts, has been consistently low in recent years.

Nonetheless, the record also demonstrates that the off-site impact of an ammonia spill could approach the hazard threshold of 500 ppm. The impact of a urea spill would be less than that of an ammonia spill, although the Company was not able to quantify and compare impacts

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441 The Company indicated that the containment structure would be periodically drained of accumulated rainfall via a normally closed drain valve (Exh. AG-2-9). The Company stated that no rainfall would be drained from the containment structure until it was ascertained that no ammonia spillage had occurred (id.). The Company further stated that a roof would cover the sulfuric acid storage area to prevent rainwater from entering the diked area (Exh. SCE-14, at 5).

of the two substances because it had not done an assessment of potential impacts of a urea spill. While the Siting Board recognizes that, based on the record, there may be valid cost, reliability or other environmental reasons for using ammonia rather than urea with an SNCR system to control NOx emissions, it appears that, on the basis of spill impacts alone, urea is preferable to ammonia.

Accordingly, based on the foregoing, the Siting Board finds that the Company has not established that the environmental impacts of the proposed facility at the primary site would be minimized with respect to safety.

x. Electric and Magnetic Fields[442]

(A) Description

SCE stated that two new overhead 115 kV transmission lines would be constructed within the TMLP property boundaries to connect the proposed TEC at the primary site to the existing switchyard at TMLP's Cleary Substation (Exhs. SCE-3, at III.1-23; EFSC-E-71). SCE noted that two existing interconnect lines, each approximately 0.83 miles in length, extend from the Cleary Substation to the regional 115 kV transmission system ("TMLP tap lines") (id.). SCE added that no new off-site transmission lines would be required to accommodate the interconnection of the proposed facility (id.).[443]

The Company stated that, in consultation with TMLP, it determined that the segments of the 115 kV transmission system most affected by the operation of the proposed facility would be the TMLP tap lines which emanate from the Cleary Substation (Exh. EFSC-V-20S). With

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

443 The Company stated that several minor interconnect line improvements, including the installation of an additional tower and an increase in the height of the existing lines, would be necessary for the TMLP tap lines to handle the power levels associated with operation of the proposed project (Tr. 18, at 10-12). The Company further stated that reconductoring of the TMLP tap lines may also be required to allow for a possible contingency, such as the loss of one line (id., at 13).

respect to field levels on the TMLP tap lines, the Company stated that while the electric field level would not change since there would be no change in transmission voltage, the magnetic field level would change due to the increase in line current as a result of operation of the proposed facility (Exh. EFSC-E-63S). The Company also stated that the TMLP tap lines are short in length, traversing the Taunton River, cultivated fields, small wetlands, and a wooded area (Exh. EFSC-E-71). The Company further stated that such a short, rural route minimizes the potential residential exposure to magnetic fields from the interconnect lines, adding that only a single residence is located in the area (id.).

The Company provided calculations of magnetic field levels along the TMLP tap line ROW, both with and without the proposed facility, indicating edge-of-ROW levels of 35 milligauss ("mG") and 14 mG, respectively, based on a nominal power output of 150 MVA[444] from the proposed facility (Exh. EFSC-E-63S).

SCE stated that EUA, who owns and maintains the regional transmission lines[445] into which the TMLP tap lines interconnect, expects it would likely reconductor two double-circuit lines[446] to accommodate the proposed project (Exh. EFSC-RR-134; Tr 18, at 5, 91 through

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444 SCE stated that the present and proposed power levels carried by the TMLP tap lines were modelled on the Bonneville Power Administration Corona and Field Effects Program (Exh. EFSC-E-63). The present power level scenario assumed 50 MVA on each of the TMLP tap lines, based on operation of all existing TMLP area generation in service with the TMLP load level at approximately 50 percent of its peak value (id.). To be conservative in its estimate of EMF levels, the Company stated that the proposed power level scenario assumed a worst-case situation of 125 MVA on each of the interconnect lines (id; Tr. 18, at 13).

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

446 At present, the TMLP tap lines interconnect into the regional 115 kV transmission

(continued…)

92). SCE also noted that EUA would be willing to reposition the two double-circuit lines in such order so as to reduce the magnetic field impacts along EUA's ROW (id.). Further, the Company indicated that the section of the EUA ROW extending north toward Bridgewater, while generally undeveloped, contains some populated areas, and that the section extending south toward Somerset is mostly undeveloped (Exhs. EFSC-3; EFSC-E-71, att.; Tr. 18, at 47 through 52).

(B) Analysis

In a previous review of proposed transmission line facilities which included 345 kV transmission lines, the Siting Council accepted edge of ROW levels of 1.8 kV/meter for the electric field, and 85 mG for the magnetic field. 1985 MECo/NEP Decision, 13 DOMSC at 228-242. Here, regarding the edge of ROW EMF levels for the 115 kV TMLP tap lines serving the primary site, the Siting Board notes that the electric field levels would remain unchanged, and the magnetic field levels, while increasing due to the operation of the proposed project, would remain well below the levels found acceptable in the 1985 MECo/NEP Decision. In addition, the regional 115 kV transmission lines owned and maintained by EUA, and into which the proposed facility would interconnect, would be positioned by EUA during planned reconductoring to minimize any magnetic fields as a result of operation of the proposed project.

The record demonstrates that the Company's interconnection plans include reasonable efforts to implement measures to minimize EMF impacts on portions of the existing transmission system affected by the proposed facility.

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[446](…continued)
system on a double-circuit line designated V5 and a single-circuit line designated S8 (Exh. EFSC-RR-130; Tr. 18, at 19 through 22). SCE's witness, Peter J. Thalmann, stated that EUA's preliminary plan would involve relocating one of the tap line interconnections from the S8 line to another double-circuit transmission line designated U6, which occupies the same ROW as the V5 and S8 transmission lines (id.).

Based on the Company's representations in this record, the Siting Board expects that: (1) as part of any reconductoring of the TMLP tap lines to accommodate the TEC, SCE and TMLP would utilize a transmission design that minimizes magnetic field impacts through positioning of such lines, and (2) as part of any TEC interconnection agreement with EUA that provides for reconductoring of any EUA lines, SCE and TMLP would seek inclusion of a transmission design that minimizes magnetic field impacts through positioning of such lines.[447]

Accordingly, based on the foregoing, the Siting Board finds that SCE has established that the environmental impacts of the proposed facility at the primary site would be minimized with respect to EMF.

b. Costs of the Proposed Facilities at the Primary Site

In this section, the Siting Board evaluates whether the Company has provided sufficient information on the costs of the proposed facility at the primary site to allow the Siting Board to determine if an appropriate balance would be achieved between environmental impacts and cost.[448]

The Company indicated that the primary site offers specific cost advantages due to the proximity of the proposed facility to (1) the existing TMLP switchyard, and the 115 kV regional transmission system, and (2) the existing TMLP water intake system and availability of the Taunton River water supply (Exh. EFSC-S-3).

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[447] In Section II.C, above, the Siting Board has required the Company to provide evidence of a signed transmission interconnection agreement.

[448] In past facility decisions, we have evaluated whether estimates of costs for the construction and operation of the proposed facilities are realistic for a facility of the size and design proposed. Enron Decision, 23 DOMSC at 132; EEC, 22 DOMSC at 135. Application of that standard of review is consistent with our statutory mandate to minimize environmental impacts of proposed facilities at the lowest possible cost. In this review, we address estimated costs only to the extent necessary to allow a comparison between the primary and alternative sites based on environmental impacts, reliability and cost.

SCE provided a construction cost estimate for the primary site of $200 million, based on its initial project design (Exh. SCE-1, at 9-1 through 9-2).[449] The Company stated that its primary site cost estimate is based on the proposed facility's location in the Taunton area generally, and includes: (1) construction costs; (2) rail connection costs; (3) electric transmission line interconnection costs; (4) steam pipeline interconnection costs; and (5) the cost of necessary engineering services, and also reflects site specific costs (id., at 9-1). The Comapny stated that its cost estimate includes a contingency allowance of five percent of the contractor's construction price, intended to cover unforeseen environmental mitigation and project development costs as well as capital cost escalation (Tr. 5, at 148; Tr. 7, at 171 through 174).

SCE argued that the cost of the proposed facilities at the primary site are realistic for a facility the size and design of the TEC (SCE Brief at 171). In support of its argument, the Company provided an analysis comparing the estimated costs of the proposed facility at the primary site with the costs of a generic CFB facility with similar characteristics to the TEC (Exhs. SCE-1, at 5-14 through 5-21; SCE-1R, at 5-15R, 5-18R, 5-20R; SCE-2BR, Appendix B; Tr. 13, at 55 through 62). SCE indicated that the proposed facility's cost compares favorably to the cost for a comparable CFB technology identified in the 1989 TAG (Exh. AG-RR-38; SCE Brief at 171). The Company argued that, based on the 1989 TAG, its analysis demonstrates that the projected capital cost of the proposed facility is lower than that of a comparable CFB technology (id.).

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[449] The Company provided a confidential update of its cost estimate, reflecting a major design change from two non-reheat boilers to a single reheat boiler (Exhs. SCE-1, at 1-1r; EFSC-RR-59). As part of its comparison of technologies, SCE provided a cost estimate of $2,064/KW in 1997 dollars reflecting the single reheat boiler design (Exh. SCE-22, at 19 through 20, attach. RLC-33). The primary factors included in the Company's cost estimate are: (1) capital costs; (2) O&M costs; (3) fuel costs; (4) interest rates; (5) availability factor; and (6) heat rate (id.).

SCE also identified the costs of several options to further minimize the environmental impacts associated with the proposed facility including: (1) the use of low sulphur coals; (2) the use of a urea-based NOx emission control system; and (3) additional noise mitigation measures.

With respect to the sulphur content of the coal, the Company provided a cost comparison for the proposed coal supply, with an average sulphur content of 1.6 percent, and three identified alternative coal supplies with sulphur contents of 1.2, 1.0, and 0.4 percent, respectively (Exhs. SCE-12, at 6 through 7, 10; AG-RR-17; AG-RR-15). The Company provided the following estimates of the total annual operating costs for the proposed coal supply, and the three coal supply alternatives: $23.36 million for the proposed coal supply, $28.33 million for the 1.2 percent supply, $27.36 million for the 1.0 percent supply, and $31.15 million for the 0.4 percent supply (Exh. AG-RR-15). Therefore, based on the Company's comparison, the annual additional costs of utilizing coal with sulphur contents of 1.2, 1.0, and 0.4 percent would be as follows: $4.97 million, $4.00 million and $7.79 million respectively (id.). The Company's data further indicated that for the lower sulphur coals, the additional costs per ton of additional SO_2 removed would be as follows: $18,825, $9,876 and $9,470 respectively (id.).[450,451]

With respect to the use of urea for NOx control, the Company's witness, Mr. Nawaz, stated that although SCE has virtually committed to ammonia, it was still studying the use of a

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450 The Company also provided calculations of the additional cost per ton of additional SO_2 removal relative to a 1.8-percent sulphur content -- the guaranteed maximum amount in the draft contract with the proposed facility's selected supplier -- as follows: $13,042 for 1.2 percent coal, $5,993 for 1.0 percent coal, and $7,253 for 0.4 percent coal (Exh. AG-RR-17).

451 Mr. Montgomery stated that several cost factors must be considered when purchasing coal with a specific sulphur content to be fired in a CFB boiler as would be used at the proposed facility (Exh. SCE-12, at 4). Specifically, Mr. Montgomery stated that the higher purchasing costs of extremely low sulphur coals must be balanced against the costs associated with purchasing larger amounts of limestone necessary for SO_2 reduction with the use of higher sulphur coals (id.). Mr. Montgomery added that approximately 60 percent of the limestone used in the combustion process is wasted and mixed with the coal ash, thereby increasing waste disposal costs (id.).

urea-based system (Tr. 6, at 27 through 28). The Company stated that the capital cost of an ammonia-based system would be approximately $500,000, and provided a capital cost estimate of $1,280,000 for a urea-based system (id., at 47; Exhs. AG-RR-19; AG-RR-18). The Company added that the $1,280,000 figure did not include the installation of equipment and piping outside the urea system contractor's likely scope of services, and did not include any associated indirect costs (id.). Mr. Nawaz stated that the cost of a urea-based system would likely add approximately one-thousand dollars more per ton of NOx removed over the cost of an ammonia-based system with equivalent capabilities[452] (Exh. AG-RR-18; Tr. 6, at 25 through 26).

Regarding additional measures to achieve a further reduction in facility noise levels, SCE identified two options providing different levels of additional noise mitigation and each option's associated component costs (Exhs. EFSC-RR-81; EFSC-E-69). The Company indicated that the six dBA reduction option would require a total additional cost of approximately $812,000 and includes: (1) a full enclosure of the induced fan housing and breeching at a cost of $160,000; (2) a quieter power transformer at a cost of $30,000 over that of a standard transformer; (3) an increased wall weight of 2 pounds per square foot for all sides of the turbine/boiler building at a cost of $350,000; and (4) an increase of eight feet in the length of the exhaust stack muffler over that proposed at an additional cost of $272,000 (Exh. EFSC-RR-81).

SCE indicated that the three dBA reduction option would require a total cost of approximately two-thirds that required for the six-dBA reduction option, or $501,000, and includes the following differences from the six-dBA reduction option (1) an increased wall weight of 2 pounds per square foot for only the southern and eastern walls of the turbine boiler building at an additional cost of $175,000, and (2) a four-foot increase in the length of exhaust

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452 In response to a record request by the Attorney General, SCE indicated that an ammonia-based NOx control system would consume ammonia at a rate of 425 lbs/hr while a urea-based system with the same NOx control capabilities would consume urea at a rate of 1,100 lbs/hr (Exh. AG-RR-18).

stack muffler over that originally proposed at an additional cost of approximately $136,000 (Exh. EFSC-E-69).

In addition to the above options, the record identified other options to further reduce environmental impacts including sound barriers to mitigate noise during on-site train activity, off-site tree planting to reduce visual impacts, an abutter property value guarantee program to reduce land use impacts, and grade separation or other measures to reduce traffic impacts associated with train transportation (see Sections III.C.2.a.iv, III.C.2.a.v, and III.C.2.a. vi, above). The Company provided limited or no cost information for each of these identified options.

With respect to sound barriers, SCE provided a confidential cost estimate for a 20-foot high sound barrier along the west side of the on-site track extension toward Railroad Avenue. SCE indicated that the identified 20-foot sound wall would be installed if required along the west side of the on-site track extension. However, the Company maintained that a second sound barrier to screen residences on the west side of the tracks from locomotive noise at the proposed idling location would be impractical based on the 1,200-foot wall length that the Company assumed would be necessary (EFSC-RR-87). See Section III.C.2.a.vi, above.

With respect to tree planting, the Siting Board notes that, in its review of CO_2 emission offsets, it has recognized a typical cost of $100 per tree to provide urban shade trees under the MASS Releaf Program (See Section III.C.2.a.i, above). Thus, a cost of $100 per tree provides a reasonable basis to consider likely additional costs for the option of off-site tree planting to help minimize visual impacts.

With respect to the option of an abutter property value guarantee program for Railroad Avenue residents with inadequate buffers from the active primary site, the record provides no cost estimate, but does indicate that most, although not all, of the approximately 12 residences located on Railroad Avenue would have line-of-sight views, over the berm, of a significant portion of the proposed facility. The record indicates that the affected properties are part of a medium density residential area. It is reasonable to assume that not all the affected property owners actually would both seek to sell their property and establish eligibility for compensation under the identified property value guarantee program. To the extent property owners did so seek to sell property and establish eligibility for compensation, the required compensation would only be a portion of the guaranteed value -- specifically, the difference between the guaranteed value and the obtainable sales price. Thus, the likely cost for the identified option of an abutter property value guarantee program, with the limited applicability as noted herein, would be reasonable.

With respect to grade crossings in downtown Taunton, the record identifies possible approaches such as grade separation and a new emergency services facility to address related traffic impact concerns, but provides no cost estimates for such approaches. While a range of approaches could be considered, clearly potential choices such as grade separation would be costly. The record also contains no cost estimates or other information regarding the possibility of two 40-car trains per week as a means to mitigate traffic impacts.

The Company has provided estimates of the overall costs of the proposed facility at the primary site, and noted specific cost advantages of siting the proposed facility at the primary site. The record contains cost information for identified options to further minimize environmental impacts at the primary site, with the exception of the option of an abutter property guarantee program to further mitigate land use impacts and options to further mitigate rail grade crossing concerns.

Accordingly, based on the foregoing, the Siting Board finds that the Company has provided sufficient information on the costs of the proposed facility, with the exception of options to further mitigate land use impacts through an abutter property value guarantee program and to further mitigate rail grade crossing concerns, such as to allow the Siting Board to determine whether an appropriate balance would be achieved among environmental impacts and cost.

c. Findings and Conclusions on the Proposed Facilities at the Primary Site

In this section, we review the consistency of the proposed facility at the primary site with our overall review standard, requiring that an appropriate balance be achieved between environmental impacts and costs. Such balancing includes trade-offs among various environmental impacts as well as trade-offs between these environmental impacts and cost.

The Siting Board has found that:

- with the implementation of SCE's proposed BACT and CO_2 mitigation, and with the exception of SO_2 emissions, the Company has established that the environmental impacts of the proposed facility at the primary site would be minimized with respect to air quality;
- the Company has demonstrated that the environmental impacts of the proposed facility at the primary site would be minimized with respect to wetlands and waterways;
- the Company has established that the environmental impacts of the proposed facility at the primary site would be minimized with respect to water supply and wastewater impacts;
- the Company has not established that the environmental impacts of the proposed facility at the primary site would be minimized with respect to land use;
- the Company has not established that the environmental impacts of the proposed facility at the primary site would be minimized with respect to visual impacts;
- the Company has not established that the environmental impacts of the proposed facility at the primary site would be minimized with respect to noise;
- the Company has not established that the environmental impacts of the proposed facility at the primary site would be minimized with respect to impacts from rail traffic, and has established that the environmental impacts of the proposed facility at the primary site would be minimized with respect to impacts from vehicular traffic.
- upon compliance with the condition to provide a signed contract for the acceptable removal of ash, as stipulated in Section III.C.2.viii.(B), above, the Company will have

established that the environmental impacts of the proposed facility at the primary site would be minimized with respect to solid waste;

- the Company has not established that the environmental impacts of the proposed facility at the primary site would be minimized with respect to safety;
- the Company has established that the environmental impacts of the proposed facility at the primary site would be minimized with respect to EMF; and
- the Company has provided sufficient information on the costs of the proposed facility, with the exception of options to further mitigate land use impacts through an abutter `property value guarantee program and to further mitigate grade crossing concerns, such as to allow the Siting Board to determine whether an appropriate balance would be achieved among environmental impacts and cost.

The record indicates that with regard to the impacts to waterways/wetlands and water supply/wastewater, and the impacts of solid waste and EMF associated with the proposed project at the primary site, there are no interrelated environmental or cost trade-offs among these concerns. Further, the record indicates no interrelated environmental or cost trade-offs relative to these concerns and the impacts related to air quality, land use, noise, visual, transportation, or safety. Accordingly, on balance, the Siting Board finds that the environmental impacts of the proposed facility at the primary site would be minimized with respect to waterways/wetlands, water supply/wastewater, solid waste, and EMF, consistent with minimizing cost and other environmental impacts.

As noted above, the Company has failed to establish that the environmental impacts of the proposed project at the primary site would be minimized with respect to air quality, land use, noise, visual, transportation and safety concerns. The record reflects that, although further mitigation of these impacts is possible, such additional mitigation could result in additional costs. Thus, to complete its review, the Siting Board must address whether environmental impacts with respect to air quality, land use, noise, visual, transportation and safety would be minimized, consistent with minimizing cost and other environmental impacts. The record indicates that: (1) there are identified options to further mitigate environmental impacts with regard to each of the these concerns; (2) the Company does not currently propose to implement such options; and (3) there are trade-offs between cost and environmental impact with respect to the implementation of such options. The Siting Board notes that with one exception, the minimization of environmental impacts relative to cost has no significant interaction among the various areas of environmental concern.[453] Therefore, the Siting Board addresses the further minimization of environmental impacts relative to cost as it relates to air quality, land use, noise, visual, transportation and safety.

Regarding air quality, as described in Section III.C.2.a.i, above, the Company has proposed a coal supply with a maximum 1.8 percent sulfur content, except for force majeure situations, and expects that the average sulfur content of its coal supply would be 1.6 percent. With use of its proposed coal supply and with a 92 percent SO_2 capture rate, the Company expects to comply with terms of its draft MDEP air quality permit limiting SO_2 emissions to 0.23 lbs per MMBtu. The Company also has identified the option of using lower sulfur content fuel, specifically alternative coal supplies containing one-quarter to three-quarters the sulfur contained in the proposed coal supply, which would significantly reduce proposed SO_2 emissions. However, the Company identified costs of $4 million to $7.79 million per year more for possible lower sulfur coal supplies, as compared with the proposed coal supply -- an additional cost of $9,470 to $18,825 per ton of avoided SO_2 emission.

In a previous review of a coal-fired generating facility, the Siting Council reviewed a similar analysis comparing use of a proposed 1.8 percent sulfur coal supply to a range of coal supplies with lower sulfur content. EEC Compliance Decision, 25 DOMSC at 321-348. In that review, based on available options to reduce SO_2 emissions below a proposed level of 0.25 lb/MMBtu at costs of $3,000 to $5,000, or less, per ton of avoided SO_2 emission, the Siting Council found that the use of lower sulfur coal may be consistent with the minimization of SO_2 emissions, consistent with the minimization of cost. Id. at 324, 330, 331. Specifically, the

453 This exception relates to one option that has been identified to further mitigate noise impacts, i.e., sound barriers up to 20 feet in height, which could be significant with respect to visual impacts.

Siting Council found that a reduced emission rate of 0.225 lb/MMBtu, based on optimization of the design and operation of the CFB boiler or by use of lower sulfur coal, or by a combination of both methods, would be consistent with a minimization of SO_2 emissions, consistent with the minimization of cost. Id. at 335, 347.[454]

Here, the proposed facility would emit SO_2 at a slightly higher rate of 0.23 lb/MMBtu based on use of 1.8 percent sulfur coal. However, SCE expects that the average sulfur content actually would be 1.6 percent. In addition, SCE expects that, by the time it contracts for installation of SO_2 control equipment, additional sulfur capture rates -- up to 93 percent -- may be achievable with vendor guarantee, at operating costs of $1,000 to $1,540 per ton. Finally, SCE could propose an SO_2 offset plan, consistent with the requirements that the Siting Council set forth for such a plan in the EEC Compliance Decision. See, 25 DOMSC at 345-346.

Thus, given the substantially higher cost of the identified low sulfur coal options, the record does not establish that use of such low sulfur coal would minimize environmental impacts consistent with the minimization of cost. However, it is reasonable that the proposed facility meet a SO_2 emission limit comparable to, and based on a choice of approaches consistent with, those set forth in the EEC Compliance Decision.

Accordingly, the Siting Board finds that, assuming a maximum SO_2 emission rate of 0.225 lb/MMBtu and the other proposed emission rates as described in Section III.C.2.a.i, above, the Company has established that the environmental impacts of the proposed facility at

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454 The Siting Council also found that, as a replacement for part or all of the required reduction in SO_2 emissions, the applicant could substitute offset reductions at other generating facilities in an amount twice the amount of emission reduction so replaced, provided half the offset reductions were in Southeastern Massachusetts -- the location of the proposed facility in that review. EEC Compliance Decision, 25 DOMSC at 341-346. The Siting Council required that any such offset reduction plan must: (1) not be more costly than achieving the reduction at that proposed facility; (2) be acceptable to MDEP or other appropriate state agency(s); (3) result in verifiable, quantifiable SO_2 emissions offsets for the operating life of that proposed facility; (4) not increase emissions of other regulated pollutants over permit levels that would apply without the offset plan; and (5) result in incremental emission reduction benefits, i.e., which would not otherwise be achieved. Id. at 345-346.

the primary site would be minimimized with respect to air quality, consistent with minimizing cost and other environmental impacts. Should the Company choose to propose an SO_2 offset plan consistent with the requirements for such a plan as set forth in the EEC Compliance Decision, as an alternative to maintaining an SO_2 emission rate of 0.225 lb/MMBtu or less, the Siting Board will review such plan to determine whether it meets said requirements and adequately minimizes air quality impacts, consistent with minimizing cost and other environmental impacts.

Regarding land use, the Company maintained that the proposed facility, with suitable buffers from residential areas and noise mitigation to meet MDEP noise guidelines, would be compatible with surrounding land use and not adversely affect property values. However, the record indicates a greater potential for land use impacts, including possible adverse impacts to residential properties, than in previous generating facility reviews, given the limited existing industrial character at Railroad Avenue, the lack of adequate buffers, including mature vegetation between the proposed TEC and Railroad Avenue, and the structural scale of the proposed CFB facility compared to that of previously reviewed facilities.

Thus, the Siting Board's concern regarding land use impacts in this review focuses on those residential properties with both limited space separation and limited presence of intervening mature vegetation, relative to the active primary site. In particular, the record indicates that the properties on the north side and east end of Railroad Avenue that abut the active primary site, and the properties on the opposite side of Railroad Avenue from such abutting properties, are inadequately buffered from the proposed facility based on both proximity and lack of intervening mature vegetation.[455]

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[455] The remaining properties on Railroad Avenue, closer to Somerset Avenue, are west of or opposite the wooded portion of the TMLP property that extends from the southwest corner of the active primary site to a frontage on Railroad Avenue. Given the extent of intervening mature vegetation on TMLP property, these properties are adequately buffered from the active primary site. Similarly, the closest residences on Somerset Avenue are adequately buffered from the active primary site by intervening mature vegetation on the TMLP property.

As described in Section III.C.2.a.iv, above, the Company has proposed a landscaped berm along the southern site boundary, and also has proposed the option of providing off-site tree plantings to further minimize visual impacts. However, the berm would only provide limited screening of the lower portion of the proposed facility leaving significant portions of higher buildings such as the coal storage shed, boiler building and the stack visible from Railroad Avenue at a distance of approximately 725 feet to the nearest building -- the coal storage shed. Further, a number of years would be required for tree plantings to attain mature size and provide effective screening. Thus, proposed and identified measures to mitigate visual impacts would not be adequate in the near term to mitigate the extent of land use impacts on the affected properties effectively.

Thus, to establish that land use impacts would be adequately minimized, the Siting Board finds that it is appropriate for SCE to pursue agreements, in good faith, with the owners of the above-identified properties that will provide a limited degree of compensation or effect an "abutter" property guarantee program.[456] To monitor compliance with this approach to minimization, SCE shall provide to the Siting Board copies of all such final agreements or a statement of reasons as to why one or more of such agreements is not forthcoming.[457]

Accordingly, the Siting Board finds that, with the mitigation required above, and with compliance with the requirement that the Company provide to the Siting Board evidence of the consistency of the proposed facility with zoning requirements as described in Section III.C.2.iv.(B), above, the Company will have established that the environmental impact of the

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[456] As discussed in Section III.C.2.b, above, although the Company did not provide a cost estimate for an abutter property value guarantee program, the cost is likely to be reasonable given the limited number of affected properties and limited time-frame for eligibility.

[457] The Siting Board notes that in requiring such compensation or guarantee program for property owners to mitigate such adverse, near-term land use impacts, we do not expect such mitigation to become the norm in future facility reviews. Rather, the Siting Board expects that the inadequately buffered proximity of the proposed facility in this case to residential properties will continue to be the exception in future facility siting reviews.

proposed facility at the primary site would be minimized with respect to land use, consistent with minimizing cost and other environmental impacts.

Regarding noise impacts, as described in Section III.C.2.a.vi, above, SCE's proposed mitigation would result in maximum nighttime noise increases from continuous sources of ten dBA and nine dBA at two residential receptors on Railroad Avenue, and seven dBA at the nearest residential receptor across the Taunton River in Berkley. However, the largest of those increases -- ten dBA at the nearest Railroad Avenue receptor -- would be reduced to five dBA 75 percent of the time by estimated berm attenuation. Further, the other two nighttime noise increases of nine dBA and seven dBA impact residential receptors near the Taunton River, where as a result of relatively quiet existing average noise levels, expected L_{dn} levels would be six to seven dBA below the EPA-recommended maximum of 55 dBA even with operation of the proposed facility.

The Company estimated a cost of $501,000 to $812,000 to further reduce the estimated nine dBA noise increase -- the increase for the receptor at the end of Railroad Avenue near the Taunton River -- by an additional three to six dBA. Assuming similar reductions could be attained at the other two receptors with the same measures, it is likely that an additional cost commitment in the above-identified range would enable SCE to reduce all calculated residential receptor L_{90} increases to a maximum of five dBA -- the maximum required by the Siting Board in the <u>1993 BECo Decision</u>. <u>See</u>, 1 DOMSB at 114.

However, although the Siting Board has not previously accepted continuous source noise impacts at residential receptors as large as those proposed by SCE, the circumstances here differ significantly from those in the <u>1993 BECo Decision</u> in that two of the affected receptors here show L_{dn} well below the EPA-recommended 55 dBA maximum, while the third affected receptor shows estimated L_{90} impacts consistent with a five dBA maximum 75 percent of the time, and approaching the ten dBA level on a worst-case basis at times within the remaining 25 percent period. Further, the Company has demonstrated that it incorporated a number of special noise mitigation measures to limit its proposed noise impacts to the levels calculated, and that additional reductions of 3 dBA or more would be costly.

Thus, based on existing noise levels, as well as the general proximity of the nearest residences, the context for addressing the level of acceptable noise impact in the present proceeding is more akin to that in the NEA Decision, where the Siting Council accepted a calculated maximum L_{90} increase of seven dBA.[458] An additional reduction of calculated L_{90} increases by two dBA here would result in a seven dBA instead of a nine dBA increase at the end of Railroad Avenue, and reduce the worst case maximum 10 dBA increase at the other Railroad Avenue receptor, applicable during a limited 25 percent time period, to eight dBA. As such, an additional two-dBA reduction in calculated nighttime noise increases for affected receptors would be reasonably consistent with the calculated noise impacts accepted by the Siting Council in the NEA Decision.

With respect to the likely cost of an additional two-dBA reduction in calculated nighttime noise increases, the record shows that a combination of measures addressing four noise sources and costing $501,000 would be required for an additional three-dBA reduction in calculated noise increase, while if such sources were addressed individually, total elimination of any one source would result in reductions of only one to 1.5 dBA. Nonetheless, it is reasonable to assume that a two-dBA reduction could be achieved at a smaller cost than a three-dBA reduction. The Company also indicated that, should it be required to incorporate further reductions, it would prefer to have the flexibility to design the most cost-effective approach for meeting that reduction -- an approach that likely would be more cost-effective than the identified three-dBA reduction option addressed in the record.

Thus, to minimize the extent of calculated increases in noise from continuous sources at residential receptors, which exceed recognized noticeability thresholds, consistent with the minimization of cost, and to be consistent with the level of noise increase accepted in past reviews with similar circumstances, the Siting Board finds that it is appropriate for SCE to provide additional noise mitigation such as to reduce calculated maximum nighttime noise

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458 The nearest residences are 700-800 feet from the proposed generating facilities in both reviews (see Sections III.2.a.iv, above, and III.3.a.iv, below).

increases of nine dBA and ten dBA at two Railroad Avenue residential receptors by an additional two dBA.

SCE's proposed noise impacts also would include calculated daytime L_{90} increases approaching ten dBA at two residential receptors during periods of on-site train activity, one day per week. Specifically, increases of ten dBA at the nearest residential receptor on Railroad Avenue, based on rail unloading and loading, and nine dBA at the residential receptor on Baker Road, based on the presence of nearby idling locomotives would occur. The Company identified the option of sound barriers to further minimize rail-related noise at both locations, and provided a confidential cost estimate for a barrier along the proposed on-site tracks in the vicinity of Railroad Avenue. However, the Company based its cost estimate on a 20-foot high wall as potentially required to reduce a L_{90} increase from 24 dBA to the MDEP limit of ten dBA, at the property line of a vacant parcel, rather than to address the Railroad Avenue residential receptor.

Based on the Company's statement that it would install a sound barrier to meet the MDEP 10 dBA limit, if required, the Siting Board expects, based on this record, that the Company would install an appropriate sound barrier to limit L_{90} increases on buildable residential parcels to the extent consistent with MDEP requirements. Further, although the rail-related noise increases at residential receptors would occur only one day per week, the Siting Board found above that it would be appropriate for SCE to further reduce by two dBA a calculated nighttime L_{90} increase that similarly would occasionally occur on a worst-case basis.

With respect to the noise impacts from idling locomotives, the Company dismissed the option of a sound barrier to reduce such impacts at the Baker Avenue receptor, citing the difficulty of breaking a noise path extending largely along, rather than away from, the tracks. However, given that the intervening railbed extends through a draw, it is unclear that the Company considered a reasonable range of alternative barrier designs to the identified design of a 1,200-foot long barrier along the railbed edge -- for example, much shorter barrier segments designed in conjunction with the topography. Further, the Company failed to consider the need for or effect of a barrier in the immediate idling location for purposes of screening residences in the vicinity of the adjacent street off Somerset Avenue north of Baker Road. Finally, as discussed below regarding at-grade rail crossing concerns, it may be appropriate for SCE to consider alternative frequencies for coal delivery -- for example, twice rather than once per week -- possibly affecting both the duration and location of locomotive idling. Given such uncertainties, the record contains inadequate information on the likely extent and cost of measures that may be appropriate for further mitigating noise impacts from idling locomotives, consistent with minimizing cost and other environmental impacts. Nevertheless, based on the record, it appears likely that cost-effective options may be available to the Company to further mitigate such noise impacts.

Thus, to minimize the extent of calculated increases in noise from rail-related sources at residential receptors, which exceed recognized noticeability thresholds, and to be consistent with the level of noise increase accepted in past reviews with similar circumstances, the Siting Board finds that it is appropriate for SCE to provide additional noise mitigation such as to (1) reduce by at least an additional two dBA the calculated maximum daytime noise increases of ten dBA at the Railroad Avenue receptors during periods of on-site rail activity, and (2) to further address noise mitigation options for reducing noise impacts from idling locomotives, including the calculated nine dBA L_{90} increase at the Baker Road receptor and likely increases as may occur at any nearer residences in the vicinity of the proposed idling location.

Accordingly, the Siting Board finds that, should the Company implement mitigation to achieve the above identified two dBA nighttime noise reduction and provide to the Siting Board an acceptable approach to achieve the above mitigation of daytime noise impacts associated with on-site rail activity the Company will have established that the environmental impacts of the proposed facility at the primary site would be minimized with respect to noise impacts, consistent with minimizing cost and other environmental impacts.

Regarding visual impacts, the Company's proposed on-site screening measures, including the landscaped berm near the southern boundary of the active primary site and the two-acre grove of spruce trees in the northwest portion of the TMLP property, would be limited in their ability to screen the proposed facility from Railroad Avenue and portions of

Somerset Avenue north of the TMLP access road. Although the Company stated it would offer a degree of off-site tree planting and approach landowners and local officials to develop specific plans, the Company failed to identify specific off-site tree planting proposals as part of this record.

Notwithstanding the absence of off-site tree planting proposals, the Company is committed to providing 75 one to 1.5 inch diameter trees per year to the City of Taunton or a private non-profit organization to support tree planting in unspecified locations. The Siting Board notes that, it is possible such tree planting can be focused to partially or fully provide appropriate off-site tree planting to address the Siting Board's concern that the visual impact of the proposed TEC be adequately minimized in the areas identified above. To the extent that commitment would not provide the appropriate tree planting for purposes of this review, the record identifies a cost of $100 per tree to provide off-site tree planting.

In a previous review, the Siting Council required a generating facility applicant to provide selective tree plantings in residential areas up to 2,000 feet from the proposed stack location to help ensure no more than intermittent visibility of the stack and other facility structures in such areas, including specified plantings in one area and plantings at the request of residents as reasonable in other areas. NEA Decision, 16 DOMSC at 408-410.[459] Here, some commitment to off-site tree planting has been made, but no linkage to reducing visibility of the proposed facility for residents in the immediate surrounding area, in particular, has been included. The record establishes that providing such plantings on public or private property to the north of Railroad Avenue south of the active primary site, and to the west of Somerset Avenue where residential properties abut the TMLP property north of the TMLP access road,

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[459] The Siting Council specified that such plantings be made along residential streets and public ways, and further that plantings be made on residential property only with the permission of affected property owners, and in public ways only with permission of appropriate municipal officials and abutting property owners. NEA Decision, 16 DOMSC at 408-409. The Siting Council also required the applicant to provide notice of the Siting Council's tree planting requirement to all potentially affected abutters, and specified time limits for residents to request tree plantings. Id..

and possibly in other surrounding residential areas, would help reduce long-term visual impacts of the proposed facility.

Accordingly, the Siting Board requires that the Company develop and implement an off-site tree planting plan that includes, as agreeable to affected landowners and affected local officials, plantings to help screen the proposed facility from Railroad Avenue and properties thereon east of the most westerly point of TMLP property frontage on Railroad Avenue, plantings to help screen the proposed facility from Somerset Avenue and properties thereon north of the TMLP access road and extending to the most northerly property abutting the TMLP property, and other plantings at locations within one-half mile of the active primary site as may be requested by property owners or appropriate municipal officials to reduce the visibility of the proposed facility consistent with a representative extent of tree planting as now exists generally along residential streets within one-half mile of the active primary site. The Siting Board finds that with implementation of such a plan, the Company will have established that the environmental impacts of the proposed facility at the primary site would be minimized with respect to visual impacts, consistent with minimizing cost and other environmental impacts. In implementing its tree planting plan, SCE: (1) shall provide tree plantings on private property only with the permission of the property owner, and in public ways only with the permission of the appropriate municipal officials; (2) shall provide written notice of this requirement to appropriate officials in Taunton and Berkley and to all affected property owners prior to commencement of construction; (3) may limit requests from local residents and City officials for tree plantings to no less than six months after initial operation of the plant; (4) shall complete all such requested plantings within one year after commencement of construction, or if based on a request after commencement of construction, within one year after such request; and (5) shall be responsible for maintaining or replacing such plantings as necessary to ensure that healthy plantings become established. The Siting Board notes that such tree plantings, where appropriate, may be undertaken in conjunction with the above-mentioned "abutter" property guarantee or compensation program.

Regarding safety, as described in Section III.C.2.a.ix, above, use of ammonia for control of NOx emissions could result in off-site ammonia concentrations approaching a hazard threshold for humans in the event of a worst-case spill. Further, as noted above, the Company identified an alternative NOx control approach based on the use of urea. However the Company cited additional installation costs of $0.78 Million, higher operating costs, and lack of industry experience for the urea-based alternative.

The Siting Board has accepted ammonia-based NOx control approaches in recent reviews involving both gas-fired and CFB coal-fired generating facilities. Cabot Power Decision, 2 DOMSB at 413-418; Altresco Lynn Decision, 2 DOMSB at 209-211; 1993 BECo Decision, 1 DOMSB at 141-143, 145-147; EEC Compliance Decision, 25 DOMSC at 304.[460] Further, SCE supported its position that its ammonia storage plan reasonably ensures an adequate level of safety based on recognized standards and past experience. Thus, given the higher cost and lack of experience with a urea-based NOx control approach, the record does not support that the identified option of a urea-based NOx control approach to further minimize safety impacts is warranted.

Accordingly, the Siting Board finds that the Company has established that the environmental impacts of the proposed facility at the primary site would be minimized with respect to safety with the use of ammonia-based NO_x control, consistent with minimizing cost and other environmental impacts.

Regarding transportation, as described in Section III.C.2.a.vii, above, SCE's proposed fuel delivery plan, which results in associated passage of trains through at-grade crossings in downtown Taunton with obstruction of such crossings for up to six minutes, has raised possible grade crossing obstruction concerns in general and in light of G.L. c. 160, § 151, in particular. SCE proposes to mitigate obstruction concerns by providing for placement of a medical emergency vehicle in downtown Taunton, on the opposite side of the Conrail track from the

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460 In 1993 BECo Decision, 1 DOMSB at 146, the Siting Board conditioned its acceptance of an ammonia-based approach on the applicant's provision of ammonia storage and transport plans for review by the local board of health.

emergency vehicle dispatch center. Nevertheless, the Siting Board has found that such provisions would not ensure that impacts associated with rail traffic would be minimized.

The Siting Board notes that identified options for further mitigating rail-related transportation impacts, including grade separation improvements or a new emergency dispatch facility for medical, police and fire vehicles, although not developed as part of this record would likely be costly. However, the Siting Board recognizes that alternative fuel delivery schedules, i.e., delivery by more frequent, smaller trains, is another option that, although not addressed on this record, may allow mitigation at an acceptable cost.

Accordingly, the Siting Board finds that, should the Company provide to the Siting Board an acceptable approach to reduce the six-minute obstruction of at-grade crossings in downtown Taunton, the Company will have established that the environmental impacts of the proposed facility at the primary site would be minimized with respect to transportation impacts, consistent with the minimization of cost and other environmental impacts. As part of its supporting analysis for such an approach, the Company should identify and compare the costs and the community or other environmental impacts of alternative train passage arrangements, and address compliance of such arrangements with G.L. c. 160, § 151.[461]

In sum, the Siting Board has found that, with the implementation of further mitigation described above for air quality, land use, and visual impacts, that the Company will have established that such impacts of the proposed facility at the primary site would be minimized consistent with the minimization of cost and other environmental impacts. Further, the Siting Board has found that with the implementation of the proposed ammonia-based NOx control technology, safety impacts of the proposed facility at the primary site will be minimized consistent with the minimization of cost and other environmental impacts. Finally, the Siting Board has found that, should the Company (1) provide the Siting Board with an acceptable

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461 The Siting Board notes that in Section III.C.2.a.vii, above, the Siting Board encouraged SCE, in cooperation with Conrail, to consult with local officials and the public in communities along the Framingham and Middleboro secondary lines prior to any commencement of train operations for the proposed TEC facility.

approach to achieve mitigation of daytime noise impacts associated with on-site rail activity, and (2) provide additional noise mitigation such as to reduce calculated maximum nighttime noise increases of nine dBA and ten dBA at two Railroad Avenue residential receptors by an additional two dBA, the Company will have established that the environmental impacts of the proposed facility at the primary site would be minimized with respect to noise impacts, consistent with minimizing cost and other environmental impacts. The Siting Board has also found that, should the Company provide the Siting Board with an acceptable approach to reduce the six-minute obstruction of at-grade crossings in downtown Taunton, the Company will have established that the environmental impacts of the proposed facility at the primary site would be minimized with respect to transportation impacts, consistent with the minimization of cost and other environmental impacts.[462]

3. Analysis of the Proposed Facilities at the Alternative Site and Site Comparison

a. Environmental Impacts of the Proposed Facilities at the Alternative Site

i. Air Quality

(A) Description

The Company indicated that emissions at the alternative site would be the same as at the primary site, and that all applicable regulations and control technologies would be the same at both sites (Exh. SCE-8, at 3). With respect to air quality impacts at the alternative site, SCE stated that it used the same ISCST and VALLEY computer models employed at the primary site to model and analyze dispersion of potential atmospheric contaminants from the proposed TEC (Exh. SCE-8, Att. B-1, at 1). The Company further stated that results of modeling,

[462] We note that, given the Company's allowance of a five percent contingency factor, it is reasonable to expect that the Company could provide the additional mitigation required herein consistent with the overall project cost estimates provided in the record and reflected in our review of project viability in Section II.C, above, our comparison of alternative technologies in Section II.B, above, and our comparison of the primary and alternative sites in Section III.C.3.c, below.

including screening modeling, refined modeling and complex terrain modeling for worst-case emissions indicated no significant air quality difference between the primary and alternative sites (Exh. SCE-8, at 3). In light of its analysis, the Company asserted that all ambient air quality standards, PSD increments, and MDEP policy limits would be maintained for the alternative site (id.).

(B) Analysis

In this proceeding, the Siting Board notes that the proximity of the alternative and primary sites as well as the similarity of their topography support the Company's conclusion that there are no significant differences in air quality impacts between the two sites.[463]

With respect to air quality, the record demonstrates that, with implementation of SCE's proposed BACT and CO_2 mitigation, and assuming water cooling at the alternative site as at the primary site, the environmental impacts for the proposed TEC would be comparable at both the alternative and primary sites.

Accordingly, based on the foregoing, the Siting Board finds that, with the implementation of SCE's proposed BACT and CO_2 mitigation, and with the exception of SO_2 emissions, the environmental impacts of the proposed facility would be minimized with respect to air quality at the alternative site. The Siting Board further finds that the environmental impacts of the proposed project at the alternative site would be comparable to impacts at the primary site with respect to air quality.

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463 The Siting Board notes that the Company's analysis at the alternative site assumes water cooling for the proposed facility, although the Company has indicated that, were it to build the proposed facility at the alternative site, it is possible that it would use dry cooling (see Section III.C.3.a.vi, below). The Siting Board also notes that SCE's analysis does not quantitatively address the impact of dry cooling on air emissions from the proposed TEC at the alternative site.

ii. Water Resources (Wetlands and Waterways)

(A) Description

The Company stated that at the alternative site it had identified 12 wetland areas scattered throughout the site (Exh. SCE-15, Att. R-5, at 1). The Company asserted that direct impacts to wetland resource areas at the alternative site could be avoided in construction of the proposed facility (id. at 2). To avoid wetland impacts at the alternative site, the Company indicated it would locate the proposed facility in the northeast portion of the site and construct the proposed rail spur and haul road within the abandoned rail ROW (id.). The Company asserted that as a result of its roadway and railbed design, road and rail construction would not impact wetlands; rather, impacts would be limited to buffer zones along the abandoned rail right-of-way (id. at 3).

With respect to off-site wetland impacts with use of the alternative site, the Company stated that, given the distance between the alternative site and the transmission interconnection point at TMLP, a new two-mile long transmission line would be required (Exhs. SCE-1, at 9-5, 9-9, 9-12; EFSC-E-71, att.). The Company indicated that the new transmission line, which likely would extend from the alternative site along the rail right-of-way to an existing transmission line ROW, and then along the existing transmission line ROW to the TMLP Cleary Substation, would border several wetland resource areas and potentially result in construction related buffer zone impacts (id.).[464]

The Company stated that impacts to off-site wetlands also might result from construction of water supply and wastewater pipelines with use of the alternative site for the proposed project (Exh. SCE-15, Att. R-5, at 4). The Company indicated that it possibly would extend the water supply and wastewater pipelines from the alternative site to existing intake/discharge locations at either the West Water Street Station or Cleary Substation, or to a new intake/discharge location on the Taunton River (id. at 16). The Company indicated that,

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464 The potential route would overlap a transmission line route previously approved by the Siting Council. See, Taunton Municipal Lighting Plant, 8 DOMSC 148 (1982). The approved route in that review largely follows an existing rail line. Id. at 152.

depending on the choice of the intake/discharge location, the water supply and wastewater pipelines would be three to six miles in length (id.; Exh. SCE-1, at 9-11). The Company specified that pursuing a new Taunton River water supply intake and wastewater disposal option would require building a new intake and outfall structure on the Taunton River, and that such construction would entail direct impacts to wetland resource areas (Exh. SCE-1, at 9-5, 9-11). The Company noted, however, that due to potential difficulties in obtaining a ROW for the southern portion of the pipeline route (i.e., paralleling the 3-mile rail spur into the TMLP property), it might be necessary to utilize dry cooling at the alternative site.[465] (Exh. SCE-1, at 9-11). The Company indicated that, in the event dry cooling was used, impacts to wetlands would be limited to those associated with transmission lines (Exhs. SCE-15, at 12; SCE-13, at 15 through 16).

Thus, in comparing the primary and alternative sites with respect to wetland impacts, the Company asserted that both sites would entail comparably negligible on-site wetland impacts but that off-site wetland impacts would be greater with use of the alternative site based on the extent of ROW impacts for transmission interconnection and possible water supply and wastewater line extensions between the site and the TMLP or other locations on the Taunton River (Exh. SCE-1, at 9-11 through 9-12).

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465 With respect to dry cooling, the Company stated than an air cooled condenser would require additional capital and operating costs, occupy more space, affect site layout, emit more noise, and result in greater emissions per net MW due to reduced efficiency in the power generation (Exhs. SCE-15, 11 through 12; AG-RR-6; AG-RR-7; Tr. 6, at 5 through 6, 40 through 45; Tr. 5, at 233 through 235). Further, the Company stated that if dry cooling were used there would be a decrease in plant efficiency because the air cooled condenser would cause higher steam back pressure (Exh. AG-RR-6). Therefore, the Company stated, a plant with an air cooled condenser would require a larger boiler, turbine and balance of plant equipment than a plant with water cooling for the same MW output (Exh. AG-RR-7). In addition, the Company stated that with dry cooling, an auxiliary cooling system using a water cooling tower would still be required to provide cooling water to turbine lube oil coolers, and other plant equipment (id.) Finally, the Company stated that the installation of the air condenser alone would cost over $26 million in addition to the installation cost of the auxiliary cooling tower which would be over $3 million (id.).

In regard to impacts on waterways, the Company asserted that, with use of water cooling, the impacts of construction and operation of the proposed TEC at the alternative site would be essentially comparable to those at the primary site (Exh. SCE-15, at 12). Thus, if dry cooling were used, the cooling water intake/discharge location on the Taunton River would be avoided (id.).

(B) Analysis

The Siting Board notes that SCE has indicated that direct impacts to wetlands could be avoided at the alternative site. The Company has, in addition, described a full range of mitigation measures, that would be used to minimize damage to wetland areas and buffers at both the primary and alternative sites as appropriate.

While the Company states that a new transmission line would be required at the alternative site, it has also indicated that the line would follow an existing rail ROW to an existing transmission ROW. The Siting Board notes that use of appropriate construction techniques and likely use of existing rail and transmission ROWs would ensure that impacts from construction of the proposed transmission line to the alternate site would be minimized.

Assuming use of water cooling at the alternative site, it would be necessary to extend water supply lines and wastewater pipelines approximately three to six miles for access to the Taunton River, depending on the route chosen. The Siting Board notes that (1) there would be significant wetland impacts associated with the use of a new discharge location since construction would create a permanent disturbance to the ecology and a permanent disturbance to wetlands along the river bank in the immediate area of the outfall construction, and (2) the wetland impacts would be reduced by extending water supply and wastewater pipelines from the alternative site to the existing TMLP West Water Street Station or Cleary Substation instead. However, the Siting Board also recognizes that there would be even less impacts to wetlands with the use of dry cooling.

The record indicates that the Company has raised significant questions regarding the use of water cooling or dry cooling at the alternative site. Specifically, with respect to water cooling, it is uncertain whether the Company would be able to obtain a ROW to construct a portion of the supply pipeline. Further, potentially significant impacts to wetland could occur depending on the location of the discharge structures. With respect to dry cooling, the Company has raised cost concerns that question whether air cooling would be a viable option. Thus, the Siting Board is unable to determine which cooling technology, water cooling or dry cooling, would help to minimize impacts with respect to wetlands and waterways at the alternative site.

Accordingly, the Siting Board finds that the environmental impacts of the proposed facility at the alternative site would not be minimized with respect to wetlands and waterways.

In comparing the proposed and alternative sites, the Siting Board has found that SCE has demonstrated that the environmental impacts of the proposed TEC at the primary site would be minimized with respect to wetlands and waterways. Further, based on the information submitted in this case, the Siting Board has found that with respect to wetlands and waterways, the environmental impacts of the proposed facility at the alternative site would not be minimized. However, the Siting Board notes that assuming water cooling is used at both the primary and the alternative sites, the most significant differences between the two sites would be the risk of off-site wetland impacts from transmission, water supply and wastewater line routing and intake/discharge facility siting with use of the alternative site. While recognizing that the extent of such risk was not developed in detail on this record, the record regarding the potential extent of such impacts is sufficient to constitute a net disadvantage for the alternative site with respect to wetlands. Further, with water cooling at the alternative site, the record indicates that impacts to waterways would be comparable. Therefore, the Siting Board finds that with use of water cooling at the alternative site, the primary site would be preferable to the alternative site with respect to impacts to waterways/wetlands. The Siting Board notes that if dry cooling is used at the alternative site, wetland impacts associated with transmission lines would still be greater than wetland impacts at the primary site. Further, dry cooling would eliminate impacts to the Taunton River, however the Siting Board has found that such impacts at the primary site would be minimized. Nevertheless, the Siting Board finds that minimal impacts to the Taunton River outweigh impacts to wetlands. Therefore, the Siting Board finds that the alternative site is preferable if dry cooling is used.

iii. Water Supply and Wastewater

(A) Description

The Company indicated that, assuming use of water cooling at the alternative site, the Company indicated that cooling water makeup would be obtained from the Taunton River and piped six miles to the site (Exh. SCE 1, at 9-2). The Company stated that the least-impact option would be to route the intake pipeline along the Conrail ROW to Weir Street and then to the existing TMLP West Water Street Station, where the existing intake structures could most likely be utilized (Exh. SCE-15, at 12, 16).[466]

With respect to water supply for plant uses other than cooling, the Company indicated that the proposed TEC at the alternative site, to the same extent as at the primary site, would rely on the municipal water system of the City of Taunton (SCE Brief at 260, 261). Thus, the Company indicated that the proposed TEC would have no adverse impact on the municipal system at the alternative site (id.).

The Company indicated that the components and quantities of wastewater discharges from the facility, including sanitary waste and stormwater would be the same at the alternative site as at the primary site (SCE Brief at 252).[467] The Company further noted that similar design features would be incorporated at the alternative site as at the primary site to address stormwater runoff (id. at 247 through 253).

[466] The Company stated that if the existing intake structures at the West Water Street Station could not be used, its next option would be to continue the pipeline to the nearby TMLP Cleary Substation (Exh. SCE-15, at 12, 16).

[467] The Company indicated that construction of the proposed TEC at the alternative site would preclude a sewer system tie-in for the TMLP and nearby residences (SCE Brief at 252 through 253).

(B) Analysis

The Siting Board notes that the Company has documented that, assuming use of water cooling, water supply demands and wastewater discharges for the proposed TEC will be the same at the alternative site as at the primary site, and that there will be no adverse impacts on the City of Taunton municipal water and sewer systems from the proposed TEC at the alternative site. The Siting Board also notes that, at the alternative site, the Company will incorporate the same full range of strategies for conservation of Taunton River water and potable water from the City of Taunton municipal water system as it will use for the proposed TEC at the primary site. Further, the record demonstrates that the demands the proposed TEC would make on the Taunton River and City of Taunton water supply system at the alternative site would be acceptable, and would, in addition, be comparable to demands of the proposed TEC at the primary site.

Accordingly, based on the foregoing, the Siting Board finds that the environmental impacts of the proposed TEC at the alternative site would be minimized with respect to water supply and wastewater. The Siting Board further finds that the primary site and alternative site are comparable with respect to environmental impacts of water supply and wastewater.

iv. Land Use

(A) Description

The Company asserted that the proposed facility would not have significant adverse impacts on land use at the alternative site, provided that suitable buffers are maintained and the design is implemented to meet MDEP noise guidelines (Exh. SCE-13, at 17).

The Company stated that the alternative site is 250 acres of Commonwealth-owned property, located adjacent to, and south of, the Miles Standish Industrial Park, of which approximately 50 acres would be used for actual facility construction (Exh. SCE-1, at 8-27).[468]

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[468] The Company stated that the 50-acres include all area to be used within the rail loop, however, the active working area for the facility is approximately 20 acres

(continued…)

The Company further indicated that the site is relatively flat, extensively disturbed uplands, with the northwest corner presently occupied by the Massachusetts Agency of Surplus Property, which is currently in a state of disrepair (id.).

SCE indicated that the surrounding land uses are the Cranes Landing Condominium complex ("Condominiums") to the north, the Dever State School to the east, and subdivisions located approximately 3,000 feet away to the southwest of the active alternative site beyond a wooded buffer area (id. at 8-27, 8-37). The Condominiums are situated 1,300 feet from the closest facility building, and 1,000 feet from the site boundary/railroad ROW (Exh. EFSC-RR-45). The Dever School is located less than one half mile from the site (Exh. SCE-1, at 8-37). The Company indicated that approximately 570 residences are located within a three quarter mile radius of the facility site (Exh. EFSC-RR-14).[469]

The Company stated that there is existing wooded buffer at the alternative site (Exh. SCE-13, at 17). However, SCE indicated that existing vegetation on the majority of the site consists of bush shrub, tree saplings and grass, with forested land limited to the southern portion of the site and the portion of the site near its eastern boundary with the Dever State School (Exh. SCE-13, at 15, Attachment R-5, at 1).[470]

The Company provided maps of existing land use for the areas surrounding its alternative site based on 1984 University of Massachusetts mapping data, updated to the end of 1991 through field work by SCE's consultant, HMM (Exh. EFSC-RR-50; Tr. 4, at 32) The Company indicated that, within a half-mile radius of the center of the alternative site, industrial land accounts for 11 percent of the land use, residential uses for six percent, forest for 54

[468](…continued)
(Exh. EFSC-RR-44).

[469] The count of residences does not include the Dever State School resident population (Tr. 4, at 30).

[470] The Company stated that if a berm was to be constructed on the alternative site, additional fill would have to be imported, whereby sufficient fill exists on the primary site for berm construction (Exh. SCE-13, at 16).

percent, open land for 23 percent, while other uses account for eight percent (id.). Expanding the radius to one mile, the Company indicated that industrial land accounts for 12 percent of the land uses, residential uses for 10 percent, forest for 56 percent, open land for 11 percent, while other uses account for 11 percent (id.).[471]

The Company stated that the site is zoned industrial, and may be categorized as light industrial use (Exh. SCE-13, at 15; Tr. 3, at 103). The Company noted that the expansion of the industrial park by the acquisition and development of the Commonwealth-owned property is a municipal objective (Exh. SCE-15, at 15). The Company indicated that, while the industrial park is upscale in nature and the tenant mix does not include heavy industry, it does not foresee that an energy facility would be detrimental to the industrial park (Tr. 3, at 103).[472] However, SCE pointed to heavy opposition from the Condominium owners at the TEC public hearing as demonstrating the potential for significant conflict with local land use purposes (id.).

SCE stated that the construction of new transmission lines are feasible, requiring only a single road crossing (Exh. SCE-15, Attachment R-5, at 1). However, the Company indicated that the construction impacts are greater than at the primary site and that the new line would pass by a number of residences (id.).

The Company's witness, Dale Raczynski, stated that use of the primary site for the proposed TEC would better serve local land use planning purposes than use of the alternative site, due to the fact that the alternative site could be developed for other industry (Tr. 1, at 144).

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[471] The Company also provided figures on land use groupings, whereby within a half-mile radius the combination of commercial, industrial and mining comprised 11 percent; and within a mile radius the percentage was 13 percent (Exh. EFSC-RR-50).

[472] The Company stated it was not knowledgeable regarding the possible existence of restrictive covenants in the industrial park by-laws which would prohibit power plants (Tr. 3, at 109).

(B) Analysis

The record indicates that, as at the primary site, existing land uses surrounding the alternative site include a substantial amount of undeveloped land, together with lesser amounts of residential, industrial and other land use areas. The Company's analysis shows more area in industrial use and less area in residential use within both one-half mile and one mile of the alternative site, as compared to the extent of such areas surrounding the primary site. However, the Company's estimate of residential density within three-quarters of a mile of the alternative site is comparable to that at the primary site.

As in the Railroad Avenue area at the primary site, the close proximity of the Condominiums presents land use compatibility concerns at the alternative site, reflected in the potential for both significant visual and noise impacts for the residents. However, the location of the TEC at the alternative site would extend a clearly established industrial zone including existing uses located adjacent to the Condominiums, although such existing use is predominantly light industry. The record also indicates that the 1,300-foot space separation between the Condominiums and the nearest TEC structure at the alternative site, together with the presence of mature trees along the property boundary, affords a degree of buffer greater than that for Railroad Avenue abutters at the primary site, and more comparable with that in some previous reviews. Further, despite the presence of wetlands, the 250-acre area of the alternative site provides flexibility, to a greater degree than at the primary site, for layout revisions to increase the buffer between the Condominiums and particular TEC structures.

With respect to zoning, the record shows that the alternative site is industrially zoned, and that the proposed facility is consistent with the objectives of industrial district zoning and municipal development. Although the Company points out that the economic benefits of locating the facility at the alternative site are not as great as the primary site, due to the potential opportunity cost of being able to utilize the alternative site for other industry, there is no firm basis on which to suggest this outcome. Although the present use of the industrial park is light industrial, the alternative site is not currently part of the industrial park. Further, the Company could not establish that a power plant would be a prohibited use if the site were to be incorporated into the industrial park.

Accordingly, based on the foregoing, the Siting Board finds that the Company has established that, assuming refinement of the facility layout and design to maximize the buffer from existing non-industrial land use, the environmental impacts of the proposed facility at the alternative site would be minimized with respect to land use.

In comparing the two sites, use of the alternative site for the proposed TEC would be consistent with zoning while the consistency of the TEC with zoning at the primary site remains unresolved. Although SCE claimed the TEC would potentially displace industrial development opportunities at the alternative site, and foster industrial development if built at the primary site based on related restoration of rail access to the Weir section of downtown Taunton, the Company failed to adequately substantiate either claim. Finally, based on relative distances to both rail activity areas and actual TEC structures, as well as the presence of mature trees, the alternative site provides a better buffer than the primary site between the proposed facility and the nearest residential abutters.

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

v. Visual

(A) Description

The Company stated that the alternative site, located adjacent to Myles Standish Industrial Park, is an area which is primarily non-residential in character (Exhs. EFSC-E-29; EFSC-E-29S). The Company noted, however, that the proposed facility at the alternative site would be in close proximity to the Condominiums which abut the west boundary of the site (id.).

In support of its visual impact analysis, the Company offered profile photographs with overlays of the proposed facility taken from three vantage points -- the Condominiums, the Dever State School and a more distant residential location (id.). The photos showed significant visibility from the Condominiums -- an open area separated from the alternative site by a stand of trees -- but limited visibility from the other vantage points (id.). As at the primary site, the Company presented photograph overlays showing the contrast between existing views at selected vantage points at the alternative site and views as they would appear with construction of the proposed facility (Exh. EFSC-E-28S).

The Company asserted that the proposed facility would have greater visual impact at the alternative site than at the primary site (Exh. EFSC-RR-45; Tr. 3, at 110 through 115). In support of this claim, the Company asserted, first, that there are many more residents at the Condominiums than residents living on Railroad Avenue; and, second, that unlike the view from Railroad Avenue, the existing view at the Condominiums does not include industrial components (id.).

(B) Analysis

As the Company has indicated, the alternative site and its immediate surroundings in this proceeding are primarily non-residential, with much of the area actually zoned industrial. Based on the photographic overlays of views presented by the Company, the greatest visual impacts at the alternative site would most likely be at the Condominiums where there is an open area separated from the alternative site by an existing stand of trees.

As at the primary site, additional mitigation for the more affected residences near the alternative site -- notably those at the Condominiums -- could be provided by off-site tree planting. Given the location of the Condominiums, adjacent to a site zoned for industrial use, an intermediate-distant, mitigated industrial view is not unacceptable. Although, as at the primary site, the Company did not provide a mitigation plan including off-site planting, the area of significant visual impact is limited to the Condominiums.[473] Accordingly, the Siting Board finds that the environmental impacts of the proposed facility at the alternative site would be minimized with respect to visual impacts.

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473 The Siting Board notes that off-site tree planting for mitigation would entail only this one set of residences.

In comparing the primary and alternative sites, the record does not support the Company's assertion that visual impacts of the proposed facility would be more broadly felt at the alternative site than at the primary site. First, the Railroad Avenue residences would be closer to the proposed facility at the primary site, with accordingly magnified visual impacts, than would the Condominiums at the alternative site. In addition, if residences along sections of Somerset Avenue abutting the primary site are included, the number of individuals affected by visual impacts at the Condominiums would not necessarily be greater than the number impacted in the vicinity of the primary site, as the Company argues.

Accordingly, the Siting Board finds the alternative site superior to the primary site with respect to visual impacts.

vi. Noise

(A) Description

SCE asserted that the noise generated by operation of the proposed TEC would not adversely affect the surrounding community at the alternative site (SCE Brief at 235 through 236). As at the primary site, SCE asserted that noise from operation of the proposed facility would be in compliance with the applicable standards, including the MDEP 10 dBA limitation on L_{90} noise increases (id.).

In support, the Company provided analyses of ambient background noise levels and expected noise increases resulting from construction and operation of the proposed facility at the alternative site (Exhs. SCE-10R, attached exhibits B, C; EFSC-E-56). To establish existing background noise levels for its noise impact analysis, SCE provided measurements of daytime and nighttime noise obtained in October 1991 for two residential receptors -- at the Condominiums and at the Dever School, located 1,500 feet and 3,600 feet, respectively, from the proposed facility (Exh. SCE-10R, attached exhibit B).[474] SCE analysis indicated that

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474 SCE developed measurements for two additional receptor locations, one representing the property boundary near an on-site road connecting to the Miles Standish Industrial (continued…)

existing noise sources include industrial park activity, other traffic and a powerhouse at the Dever School (id.).

To determine noise impacts from operation of the proposed facility at the primary site, SCE provided estimates of combined facility and background noise by receptor both for daytime periods, with contributions from train related activities expected one day per week, and for nighttime periods (id., attached exhibit C). The results of SCE's analysis indicate that, with facility operation and on-site train activity, daytime L_{90} levels would increase by four dBA at the condominium receptor and by eight dBA at the Dever School receptor (id.). The analysis further indicates that, with facility operation, nighttime L_{90} levels would increase by 11 dBA at the condominium receptor and by three dBA at the Dever School receptor (id.).

SCE stated that, although it had considered various layouts to minimize environmental impacts generally, it had not optimized the layout to minimize noise impacts in balance with competing environmental and other considerations (Exh. EFSC-E-56). SCE further stated that the size of the site provides layout flexibility, and noted as an example that the cooling tower, or air cooled condenser if used, could be moved further away from the condominium receptor (id.). Specifically, SCE indicated that relocation of the cooling equipment 200 feet toward the center of the site would reduce the calculated nighttime L_{90} increase at the condominium receptor by two dBA -- to nine dBA -- while increasing the calculated L_{90} increase at the Dever School receptor by one dBA (id.).[475,476] SCE also noted that the eight dBA calculated increase in daytime L_{90} noise at the Dever School receptor reflects noise from idling locomotives, and

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474(…continued)
Park and one representing a residential receptor near the rail line access point 1.5 miles south of the site (Exh. SCE-10R, attached exhibit B).

475 SCE's initial calculations showed that a cooling tower and an air cooled condenser would produce the same L_{90} contributions at the respective receptors -- 44 dBA at the condominium receptor and 34 dBA at the Dever School receptor (Exh. SCE-10R, attached exhibit C).

476 The Company indicated that the daytime increase in L_{90} level at the condominium receptor would be reduced to three dBA (Exh. EFSC-RR-88).

that a possible relocation of the idling locomotives would reduce the calculated increase to five dBA without increasing noise from idling locomotives at the condominium receptor (Exh. EFSC-RR-88).

The Company provided no estimates of existing or expected L_{dn} levels at the alternative site. In comparing the Company's noise measurements for the condominium and Dever School receptors with the Company's autumn measurements for residential receptors at the primary site, the Siting Board notes that the existing average noise levels at the alternative site receptors are, on balance, generally comparable to those at the Railroad Avenue, Boylston Street and Berkley Street residential receptors at the primary site -- receptors for which the Company's estimates of existing L_{dn} level are near or above the EPA-recommended maximum of 55 dBA (Exhs. SCE-10R, attached exhibit B; EFSC-E-57S at 7-23, 7-32 through 7-35; Tr. 7, at 87).

The Company indicated that all noise mitigation measures incorporated in the proposed facility design at the primary site also were assumed for purposes of the alternative site noise impact calculations, with the exception of the proposed berm between the active primary site and Railroad Avenue (Exh. SCE-10R, attached exhibit C). However, the Company indicated that it assumed the use of a standard wet cooling tower at the alternative site, but proposed use of a special low-noise cooling tower at the primary site (Exhs. SCE-10R, attached exhibit C at 2; Exh. EFSC-E-57S at 7-19).[477,478]

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477 The Company indicated that the special low-noise cooling tower was incorporated into the proposed TEC in conjunction with revisions to the primary site noise analysis, developed in response to Information Request EFSC-E-57 (Exhs. EFSC-E-20S, EFSC-E-57S).

478 The Company's calculated L_{90} noise contributions from the cooling tower range from 25 dBA to 33 dBA at residential receptors at the primary site, with attenuation over distances of 1,350 feet to 2,000 feet but without berm attenuation, but are 34 dBA and 44 dBA at the two alternative site residential receptors, with attenuation over distances of 3,600 feet and 1,500 feet, respectively (Exh. SCE-10R, attached exhibit B at 2, attached exhibit C, tables 3A, 4A; Exh. EFSC-E-57S at 7-42).

(B) Analysis

The Company's calculations of noise impacts at two residential receptors, together with the Company's suggested adjustments for a 200-foot relocation of the cooling tower, indicate that nighttime noise impacts from continuous sources would approach the MDEP 10-dBA limit and, therefore, would be generally comparable to such impacts at the primary site. However, the record indicates that cooling tower noise would be dominant in the adjusted 9-dBA impact estimate for the condominium receptor, and further indicates that SCE apparently assumed use of a noisier cooling tower at the alternative site than at the primary site.

With respect to daytime noise impacts, the Company calculated a noise impact of eight dBA at the Dever School receptor due to locomotive idling -- comparable to a similar impact from locomotive idling at the primary site Baker Road receptor as well as train activity noise impact at the Railroad Avenue receptor. However, the Company agreed that a relocation of the idling locomotive source would reduce its noise impact to five dBA at the Dever School receptor, without any identified disadvantage of such a change for other residential receptors.

Although the record does not identify options for additional mitigation to further minimize noise impacts at the alternative site, incorporation of the special low-noise design cooling tower likely could significantly reduce the calculated nighttime noise impacts at the condominium receptor. The record indicates that, in general, the Company proposes to use a facility design at the alternative site comparable to that at the primary site, with the exception of the incorporation of a berm at the primary site. Further, the record identifies no options to further mitigate cooling tower noise impacts at either site.

Accordingly, based on the foregoing, the Siting Board finds that, assuming identified site layout refinement as discussed above and use of a wet cooling tower incorporating a special low-noise design, the Company has established that the environmental impacts of the proposed facility at the alternative site would be minimized with respect to noise.

In comparing the two sites, the record clearly establishes that daytime noise impacts would be less at the alternative site than the primary site during periods of on-site train activity. With incorporation of a special low-noise design cooling tower, the record further indicates that nighttime noise impacts at the alternative site likely would be less than those at the primary site, given the calculated primary site impacts at the Railroad Avenue receptor, during periods of reduced berm attenuation, as well as at the two residential receptors near the Taunton River.

Accordingly, the Siting Board finds that the alternative site is preferable to the primary site with respect to noise impacts.

vii. Transportation

(A) Description

The Company stated that rail transport would be used to deliver coal to, and remove ash from, the alternative site and indicated that there is an active rail spur serving the alternative site, with sidings onto the site itself (Exh. SCE-1, at 8-37). The Company asserted that the routing and rail traffic considerations for serving the alternative site along the Conrail and Amtrak lines, and the potential traffic impacts from such rail activity, would be comparable to the considerations and impacts at the primary site (SCE Brief at 287). The Company submitted a map, however, of the Taunton area indicating that, because the alternative site is located to the west and north of the Taunton Square area, rail delivery could proceed to the alternative site without passage through downtown Taunton and the attendant disruption of traffic and emergency vehicle passage there (Exh. HO-RR-139B).

With respect to vehicular traffic impacts at the alternative site, the Company indicated that the proposed facility would be accessed via the Miles Standish Industrial Park entrance near the Route I-495 and Bay Road interchange (Exh. SCE-13, att. M-1, at 1). The Company indicated that for the alternative site, as at the primary site, it had undertaken a traffic study which evaluated the impact of TEC related traffic during peak construction and during later operation of the facility, relative to conditions without the facility (id.). The Company indicated that operation of the proposed facility would result in more congested LOS at two intersections during construction, but no long-term deterioration of LOS as a result of operation of the proposed facility (id. at 3).[479] The Company asserted that, on the basis of its analysis, the proposed TEC at the alternative site, when operational, would have a negligible impact on traffic (id. at 8).[480]

(B) Analysis

The Siting Board notes that impacts of rail transportation to and from the proposed TEC at the alternative site would utilize nearly all of the route affected by rail transportation for the primary site. Thus, impacts along the route, notably at the grade-crossings along the secondary track segments extended from Framingham to Taunton, would be comparable to those identified in conjunction with rail transport to and from the primary site. Given the location of the alternative site adjacent to the Middleboro secondary line northwest of downtown Taunton, however, rail impacts in the relatively built-up downtown Taunton area would be avoided with use of the alternative site.[481]

With respect to vehicular traffic, the record shows that, as at the primary site, peak construction activity for the proposed TEC would result in some deterioration of traffic levels of service. However, unlike at the primary site, the record also shows the existence of LOS F conditions at Route I-495 ramps serving the alternative site. The Siting Board further notes

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479 The Company indicated that, at peak construction, LOS at the intersection of Bay Street with Industrial Park Road and Medical Drive would drop from C to D, while LOS for left turns at the Bay Street/I-495 southbound off-ramp would drop from B to C (Exh. SCE-13, att. M-1, at 3).

480 The Company noted that, for left turn movements off three of the four I-495 ramps, conditions are currently classified as LOS F (Exh. SCE-13, att. M-1, at 8). The Company asserted that the traffic to the alternative site during both construction and operation of the proposed facility, therefore is likely to be affected by time delays (id.).

481 Given the potential for community concerns with the estimated increase in the extent of train traffic -- both larger and more frequent trains -- along the Framingham and Middleboro Secondary lines, the Siting Board encourages SCE, in cooperation with Conrail, to consult with local officials and the public in such communities prior to any commencement of train operations for the proposed TEC facility.

that, unlike at the primary site, the Company has not identified traffic design or operation measures in consultation with relevant public officials to mitigate vehicular traffic congestion aggravated by construction and subsequent operation of the proposed facility at the alternative site.

Generally, the Siting Board expects that, with similar planning at the alternative site as at the primary site, vehicular traffic impacts could be minimized. To the extent LOS F conditions prevail at Route I-495 ramps, additional measures, for example, timing construction traffic to avoid morning and afternoon traffic peaks, may be warranted at the alternative site. However, such measures to minimize traffic impacts were not adequately discussed in the record.

Accordingly, based on the foregoing, the Siting Board finds that the environmental impacts of the proposed facility at the alternative site would be minimized with respect to rail traffic, but would not be minimized with respect to vehicular traffic.

In comparing rail traffic impacts of the proposed facility at the primary and alternative sites, the record indicates that the principal concern with either site would be passage of the nearly mile-long trains over secondary rail lines from Framingham. However, at the primary site there is also the concern of rail impacts in the downtown area of Taunton. These impacts would be avoided with use of the alternative site. In comparing vehicular traffic impacts of the proposed facility at the primary and alternative sites, the record demonstrates that although the information was not provided relative to the alternative site, the potential exists for identifying traffic design and operation measures that would ensure that vehicular traffic impacts would be minimized at the alternative site as at the primary site resulting in comparable vehicular traffic impacts.

Accordingly, the Siting Board finds that, on balance, the alternative site is preferable to the primary site with respect to rail impacts, and comparable to the primary site with respect to vehicular impacts.

viii. Solid Wastes

(A) Description

The Company asserted that methods of generation, handling and disposal of ash and miscellaneous wastes at the alternative site would be comparable to methods applied to ash and miscellaneous wastes at the primary site for the same purposes (SCE Brief at 289). The Company asserted that quantities and impacts of solid waste generation, handling and disposal would be comparable at the primary and alternative sites (id.).

(B) Analysis

The record shows that, as at the primary site, the proposed facility at the alternative site would generate a significant amount of solid waste, primarily ash, and include a range of facility design measures to handle and remove such ash properly. The Company also would seek a commercially viable, environmentally benign use for ash generated by the facility, and would, potentially, contract with its coal supplier for removal and out-of-state disposal of ash from the proposed facility. However, the Company has not provided documentation relative to the Company's ultimate arrangement for removal and disposal of solid waste from the proposed TEC at the alternative site. In Section III.C.2.c, above, the Siting Board required SCE to submit either (1) a signed agreement for the removal of ash, which includes provisions to ensure safe and environmentally acceptable removal thereof, or (2) a signed coal supply contract, which includes specific provisions to ensure safe and environmentally acceptable removal of the ash. If SCE complies with the condition regarding solid waste removal, the Company would be able to ensure that the environmental impacts of the proposed facility at either the alternative site or primary site would be minimized with respect to solid waste.

Based on the foregoing, the Siting Board finds that, upon compliance with the condition to provide a signed contract for the acceptable removal of ash, as stipulated above, the Company will have established that the environmental impacts of the proposed facility at the alternative site would be minimized with respect to solid waste.

Accordingly, the Siting Board finds that the primary site is comparable to the alternative site with respect to environmental impacts of solid waste.

ix. Safety

(A) Description

The Company stated that all proposed safety measures and spill control plans for the proposed TEC would be incorporated at either the primary or alternative site (SCE Brief at 292). As at the primary site, therefore: (1) all chemical delivery, unloading, storage, transfer and usage at the proposed TEC would take place in designated areas engineered to contain and treat potential spills; (2) spills occurring inside the plant would be routed through a floor drain system into a waste equalization tank, to be treated and discharged with plant effluent; (3) oil spills would be captured via a water/oil separator; and (4) any transformer leaks would either be absorbed by gravel cover or trapped by a closed drain in the transformer yard (Tr. 6, at 54 through 55; Exh. SCE-14, at 4 through 5). The Company's statement with respect to the primary site, that ammonia would pose a greater storage hazard than urea, would also be applicable to the alternative site (Tr. 2, at 8). The Company provided an analysis of the consequences of a release of aqueous ammonia from storage at the primary site, but did not model such consequences at the alternative site (Exh. SCE-8, att. B-2).

(B) Analysis

The Siting Board notes that at the alternative site, as at the primary site, the CFB design of the proposed facility, and proposed coal handling measures, would limit the risk of coal dust explosion. The Siting Board further notes that design of the proposed facility at the alternative site would incorporate measures to avert spills of hazardous materials and to contain any such accidental spills.

The Siting Board notes, based on modeling done at the primary site, that concentrations of aqueous ammonia vapor released in an accidental spill at the alternative site would likely drop below the 500 ppm IDLH toxicity threshold by or before the alternative site property boundary. Nonetheless, the record shows that the Company did no modeling of consequences of a release of aqueous ammonia from storage at the alternative site. Further, based on the record, it appears that an accidental spill of ammonia at any site would be likely to have greater impacts than an accidental spill of urea.

As at the primary site, the Siting Board also recognizes that, based on the record, there may be other valid reasons for using ammonia rather than urea with an SNCR system to control NOx emissions at the alternative site; however, it appears that, on the basis of potential spill impacts alone, urea is preferable to ammonia.

Accordingly, based on the foregoing, the Siting Board finds that the impacts of the proposed facility would not be minimized with respect to safety at the alternative site. The Siting Board further finds that environmental impacts at the alternative site would be comparable to impacts at the primary site with respect to safety.

x. Electric and Magnetic Fields

(A) Description

In order to connect the proposed facility at the alternative site to the regional 115 kV transmission system, SCE stated that use of an additional seven miles of new and existing transmission interconnecting facilities within the TMLP system would be necessary, in addition to the same interconnection requirements on the 0.83-mile TMLP tap lines and on the EUA system as required for the TEC at the primary site (Exh. EFSC-E-71). Specifically, the Company indicated that an additional two-mile segment of new double-circuit 115 kV transmission lines would be required to deliver the proposed project's power from the alternative site[482] to TMLP's Whittenton Junction substation ("Whittenton Substation"), from where two existing five-mile-long, 115 kV transmission lines extending to the Cleary Substation would be utilized to access the TMLP tap lines and the regional 115 kV transmission system (id. att.). The Company stated that the new double-circuit construction would extend the

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[482] The Siting Board notes that any new segment of 115 kV transmission line which exceeds one-mile in length would require Siting Board approval. Prior to the issuance of any approval, a Siting Board review of the Company's detailed facility design and route, alternate designs and routes, and associated EMF impacts is required.

transmission system north from the Whittenton Substation along an existing railroad ROW to the alternative site, and that the existing 115 kV transmission lines extending from the Whittenton Substation to the Cleary Substation predominantly follow a railroad ROW (id.). The Company stated that the existing 115 kV transmission lines from the Whittenton Substation to the Cleary Substation have not been recently rated and added that it is unclear as to what upgrades would be necessary to accommodate the proposed project (Exh. EFSC-E-71).

With respect to minimizing EMF along the existing five-mile segment of the interconnect route from the Whittenton Substation to the Cleary Substation, SCE stated that the existing 115 kV transmission lines are primarily of double-circuit construction, and added that the associated line configurations may have been previously designed to minimize magnetic fields along the ROW (id.). The Company indicated that, compared to the primary site, the alternative site interconnect route would affect a greater number of residences along its overall seven-mile length (Exh. EFSC-E-71, att.).

(B) Analysis

The Siting Board notes that the proposed facility at the alternative site would involve the same transmission impacts as would occur at the primary site in addition to further transmission impacts along the seven-mile segment of transmission interconnect between the proposed facility at the alternative site and the Cleary Substation. Further, of that seven-mile span, a new two-mile segment of double-circuit interconnect lines could be configured to minimize EMF impacts. Although the Company failed to provide estimates of EMF levels along this segment,[483] or any other segment of the interconnecting or regional transmission

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483 At the primary site, the Siting Board notes that the proponent assumed a 150 MVA power output from the TEC in its EMF calculations for the TMLP tap lines, together with an additional 100 MVA from existing TMLP generation facilities at TEC. Here, the Company stated that approximately 150 MVA would flow over the additional seven-mile 115 kV interconnect from the proposed facility towards the Cleary Substation (Exh. EFSC-E-71). Further, we note that the new two-mile interconnection segment extending from the proposed facility at the alternative site to the Whittenton

(continued…)

system associated with operation of the proposed facility at the alternative site, Siting Board review of such new two-mile transmission lines in a separate proceeding would be required.

With respect to the existing five-mile segment of transmission lines that would be used in conjunction with the new two-mile segment, the record indicates that the lines are predominately of double-circuit construction and may already be configured for EMF minimization. However, the record is unclear as to the level and direction of power flows the lines would handle in the absence of output from the proposed facility, the resultant level of power flow with operation of the proposed facility, and any upgrades which might be required to accommodate the interconnection of the proposed facility at the alternative site. Further, the Siting Board notes that the Company failed to provide estimates of EMF levels on the five-mile segment for a 150 MVA or other power flow either with or without operation of the proposed facility at the alternative site. Finally, the record indicates that, due to the considerable length of the transmission interconnect, EMF impacts would affect additional areas of varying population along the interconnect route.

The record demonstrates that the Company's interconnection plans include use of existing TMLP lines with possible EMF minimization due to previous design considerations and opportunity for future EMF minimization in conjunction with system upgrades as a result of the proposed facility. Further, the design of the new two-mile segment would be subject to Siting Board review in a separate proceeding.

As at the primary site, the Siting Board expects that: (1) as part of any reconductoring of the TMLP tap lines to accommodate the TEC, SCE and TMLP would utilize a transmission design that minimizes magnetic field impacts through positioning of such lines; (2) as part of any TEC interconnection agreement with EUA that provides for reconductoring of any EUA

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[483](…continued)

Substation would be of double-circuit construction, enabling the Company to position the lines in order to minimize the EMF present as the sole consequence of operation of the proposed project. Therefore, the Siting Board recognizes that the likely EMF levels along the new two-mile segment would be equal to or less than those estimated at the primary site for the 0.83-mile interconnect lines.

lines, SCE and TMLP would seek inclusion of a transmission design that minimizes magnetic field impacts through positioning of such lines; and (3) if it is determined that reconductoring is required on the five-mile segment of existing interconnect, and regarding the new two-mile segment of interconnect, SCE and TMLP would seek inclusion of a transmission design that minimizes magnetic field impacts through positioning of such lines.

Accordingly, based on the foregoing, the Siting Board finds that SCE has established that the environmental impacts of the proposed facility at the alternative site would be minimized with respect to EMF.

In comparing the likelihood of human exposure to EMF impacts as a result of operation of the proposed project at either the primary or alternative site, the Siting Board notes that the calculated magnetic field levels at the primary site are well below the levels accepted in the 1985 MECo/NEP Decision, as would be the likely levels along the new three-mile segment of interconnect at the alternative site. However, in comparing the relative extent of affected new and existing interconnection lines together with the presence of human population in the areas of such interconnect lines at the primary and alternative sites, the Siting Board finds that, based on the foregoing, the primary site is preferable to the alternative site with respect to EMF impacts.

b. Costs of the Proposed Facilities at the Alternative Site

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

SCE indicated that the proposed facility's design at the alternative site would be essentially the same as that planned for the primary site, including the measures to minimize environmental impacts (SCE Brief at 301). SCE provided a construction cost estimate for the alternative site of $211 million, which like the primary site cost estimate, was developed based on the initial two-boiler TEC design (Exh. SCE-1, at 9-1 through 9-2; SCE Brief at 172, citing, Exh. SCE-2B, app. H) (see Section III.C.2.b, above) . The Company explained that the three major factors attributable to higher construction costs at the alternative site are: (1) considerably longer lengths of water supply/effluent lines used in conjunction with wet cooling[484,485] ($6.8M);[486] (2) a new rail transportation loop required to allow coal unloading and ash loading without disrupting rail traffic on the main railroad line; and (3) approximately two additional miles of new electrical interconnect power lines (Exhs. SCE-1, at 9-2 through 9-3; EFSC-E-71; SCE Brief at 173, citing Exh. SCE-2B, app. H).

As discussed in Section III.C.2.b, above, the Company identified costs for design options to further minimize environmental impacts of the proposed facility at the primary site, including: (1) the use of low-sulphur coals; (2) the use of a urea-based NOx emission control system; (3) additional noise mitigation measures; and (4) measures to reduce visual impacts. The Company did not identify separate costs for implementing such options at the alternative

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484 As a possible alternative cooling design, the Company indicated that it could install an air cooled condenser if necessary to avoid previously identified environmental impacts or other impediments associated with the long lengths of water supply/effluent pipelines (See Section III.C.3.a.ii, above) (Exh. SCE-1, at 9-2). The Company stated that the air cooled condenser option would add over $26 million to facility construction costs at the alternative site (Tr. 6, at 5). The Company added that the $26 million air cooled condenser estimate did not include the related costs of additional plant operations, an auxiliary cooling tower, or additional noise mitigation measures (Exh. AG-RR-7). The Company's witness, Mr. Nawaz, testified that additional noise mitigation measures on the air cooled condenser would add approximately $3 million to $3.5 million to the $26 million estimate (Tr. 6, at 42 through 43).

485 In the event that wet cooling is not used at the alternative site, the Siting Board notes that while an air-cooled condenser would dramatically increase the construction cost of the proposed facility, the costs of several wet-cooling components no longer necessary would provide a significant offset to the high costs associated with the air-cooled condenser.

486 The Company also considered additional intake and discharge locations which would require approximately half the length of water and effluent lines as is referenced with respect to the $6.8 million estimate (Exh. SCE-15, att. R-5, at 3 through 4).

site. For purposes of its review, the Siting Board presumes the additional costs to implement such options at the alternative site would be comparable to the estimates provided for implementation at the primary site.

The Company has provided estimates of the overall costs of the proposed facility at the alternative site, as well as components of capital and operational costs which are site dependent. The Siting Board finds that the Company has provided sufficient information on the costs of the proposed facility at the alternative site to allow the Siting Board to determine 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 $11 million for the primary site over the alternative site.

However, regarding the 6.8 million dollar figure that the Company identified for water supply and effluent lines from the alternative site to the intake/discharge location at the primary site, the Siting Board notes that the Company also considered additional intake and discharge locations which would require approximately half the length of water and effluent lines referenced in the 6.8 million dollar estimate. Therefore, the Siting Board notes that the costs for the water supply and the effluent lines at the alternative site would likely be between 3.4 million to 6.8 million dollars. Thus it is possible that the capital cost advantage of the primary site could be reduced to approximately $7.5 million.

Based on the above, the Siting Board finds that the Company has demonstrated that the cost of constructing and operating the proposed facility at the primary site would be less than the cost at the alternative site, even in the event that water supply and wastewater pipeline lengths are reduced by approximately half the length -- about three miles -- in conjunction with use of the alternative site.

Accordingly, the Siting Board finds that construction of the proposed facility at the primary site is preferable to construction of the proposed facility at the alternative site with respect to cost.

c. Findings and Conclusions on the Proposed Facilities at the Alternative Site and Site Comparison

In this section, we review the consistency of the proposed facility at the alternative site with our overall review standard, requiring that an appropriate balance be achieved among environmental impacts and costs. Such balancing may include trade-offs among conflicting environmental impacts as well as trade-offs between respective environmental impacts and cost. We then compare the two sites with regard to their respective environmental impacts and costs to determine which site is superior with respect to minimizing environmental impacts consistent with minimizing cost.

The Siting Board has found that:

- with the implementation of SCE's proposed BACT and CO_2 mitigation, and with the exception of SO_2 emissions, the environmental impacts of the proposed facility would be minimized with respect to air quality at the alternative site;
- the environmental impacts of the proposed project at the alternative site would be comparable to impacts at the primary site with respect to air quality;
- the environmental impacts of the proposed facility at the alternative site would not be minimized with respect to wetlands and waterways;
- with use of water cooling at the alternative site, the primary site would be preferable to the alternative site with respect to impacts to wetlands and waterways;
- with use of air cooling at the alternative site, the alternative site would be preferable to the primary site with respect to impacts to wetlands and waterways;
- the environmental impacts of the proposed TEC at the alternative site would be minimized with respect to water supply and wastewater;
- the primary site and alternative site are comparable with respect to environmental impacts of water supply and wastewater;
- the Company has established that, assuming refinement of the facility layout and design to maximize the buffer from existing non-industrial land use, the environmental impacts of the proposed facility at the alternative site would be minimized with respect to land use;

- the alternative site would be preferable to the primary site with respect to land use;
- the environemtnal impacts of the proposed facility at the alternative site would be minimized with respect to visual impacts;
- the alternative site is preferable to the primary site with respect to visual impacts;
- assuming identified site layout refinement as discussed above and use of a wet cooling tower incorporating a special low-noise design, the Company has established that the environmental impacts of the proposed facility at the alternative site would be minimized with respect to noise;
- the alternative site is preferable to the primary site with respect to noise impacts;
- the environmental impacts of the proposed facility at the alternative site would be minimized with respect to rail traffic, but would not be minimized with respect to vehicular traffic;
- on balance, the alternative site is preferable to the primary site with respect to rail impacts, and comparable to the primary site with respect to vehicular impacts;
- upon compliance with the condition to provide a signed contract for the acceptable removal of ash, as stipulated above, the Company will have established that the environmental impacts of the proposed facility at the alternative site would be minimized with respect to solid waste;
- the primary site is comparable to the alternative site with respect to environmental impacts of solid waste;
- the environmental impacts of the proposed facility at the alternative site would not be minimized with respect to safety;
- environmental impacts at the alternative site would be comparable to impacts at the primary site with respect to safety;
- SCE has established that the environmental impacts of the proposed facility at the alternative site would be minimized with respect to EMF;
- the primary site is preferable to the alternative site with respect to EMF impacts;

- the Company has provided sufficient information on the costs of the proposed facility at the alternative site to allow the Siting Board to determine whether an appropriate balance would be achieved among environmental impacts and cost;
- the Company has demonstrated that the cost of constructing and operating the proposed facility at the primary site would be less than the cost at the alternative site, even in the event that water supply and wastewater pipeline lengths are reduced by approximately half the length -- about three miles -- in conjunction with use of the alternative site; and
- construction of the proposed facility at the primary site is preferable to construction of the proposed facility at the alternative site with respect to cost.

The record indicates that with regard to the impacts to water supply/wastewater, land use, visual, transportation and noise, and the impacts of solid waste and EMF associated with the proposed project at the alternative site, there are no interrelated environmental or cost trade-offs among these concerns. Further, the record indicates no interrelated environmental or cost trade-offs relative to these concerns and the impacts related to air quality, waterways/wetlands, or safety. Accordingly, on balance, the Siting Board finds that the environmental impacts of the proposed facility at the alternative site would be minimized with respect to water supply/wastewater, land use, visual, transportation and noise, and the impacts of solid waste and EMF, consistent with minimizing cost and other environmental impacts.

As noted above, the Company has failed to establish that the environmental impacts of the proposed project at the alternative site would be minimized with respect to air quality, waterways/wetlands and safety. The record reflects that, although further mitigation of these impacts is possible, such additional mitigation could result in additional costs. Thus, to complete its review, the Siting Board must address whether environmental impacts with respect to air quality, waterways/wetlands and safety would be minimized, consistent with minimizing cost and other environmental impacts. The record indicates that: (1) there are identified options to further mitigate environmental impacts with regard to each of the these concerns; (2) the Company does not currently propose to implement such options; and (3) there are trade-offs between cost and environmental impact with respect to the implementation of such options.

The Siting Board notes that with one exception, the minimization of environmental impacts relative to cost has no significant interaction among these various areas of environmental concern.[487] Thus, the Siting Board first considers the issues associated with waterways/wetlands and then reviews the trade-offs between air quality and safety as they relate to the minimization of cost and other environmental impacts.

With respect to waterways/wetlands, the Siting Board found that the record indicates that the identified option of air cooling at the alternative site could further minimize impacts to waterways/wetlands as it would avoid withdrawal/discharge of cooling water from/to the Taunton River, as well as the installation of water supply and wastewater pipelines between the Taunton River and the alternative site, which potentially would affect wetlands. The record further indicates that, although this identified option represents an approach to further minimize waterways/wetlands impacts, SCE might conclude that air cooling was necessary in any case in the event that it could not obtain the necessary rights or approvals to install the water supply and wastewater pipelines needed to allow use of water cooling.

With respect to trade-offs among waterways/wetlands, cost and other environmental concerns, the record indicates that a net additional cost of at least $22 million to $26 million -- an additional installation cost of $29 million to $29.5 million less the avoided cost of $3.5 million to $6.8 million for water supply and wastewater lines -- would be required for use of air cooling instead of water cooling at the alternative site. Additionally, use of air cooling would result in higher air emissions associated with lower operating efficiency, and higher noise impacts including a nighttime residential receptor L_{90} increase approaching the MDEP ten-dBA limit. Thus, on balance, the Siting Board finds that the record establishes that water cooling is preferable to air cooling at the alternative site with respect to the minimization of impacts to waterways/wetlands consistent with the minimization of cost and other environmental impacts.

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[487] This exception relates to the trade-offs between noise, air quality and waterways/wetlands impacts associated with air cooling.

Accordingly, the Siting Board finds that with use of water cooling at the alternative site, environmental impacts of the proposed facility at the alternative site would be minimized with respect to waterways/wetlands, consistent with the minimization of cost and other environmental impacts.

As noted in Section III.C.3.a.i, above, the Siting Board found that air quality impacts were not minimized with respect to SO_2 emissions. In Section III.C.2.c, above, regarding the primary site, the Siting Board addressed the balance between environmental impact and cost for the identified option of using lower sulfur coal to further minimize SO_2 emissions. The trade-offs between SO_2 emissions and cost with respect to sulfur content at the alternative site would correspond to those at the primary site. For the same reasons set forth in Section III.C.2.c, above, the record does not establish that use of low sulfur coal at the alternative site would minimize environmental impacts consistent with minimizing cost and other environmental impacts. However, it is reasonable that the proposed facility meet a SO_2 emission maximum comparable to that set in the EEC Compliance Decision, based on a choice of approaches consistent with those set forth in that decision.

Accordingly, the Siting Board finds that, assuming a maximum SO_2 emission rate of 0.225 lb/MMBtu and other proposed emission rates as described in Section III.C.2.a.i, above, the Company has established that the environmental impacts of the proposed facility at the alternative site would be minimized with respect to air quality, consistent with the minimization of cost and other environmental impacts.

In Section III.C.2.c, above, regarding the primary site, the Siting Board also addressed the balance between environmental impact and cost for the identified option of using urea instead of ammonia for NOx emission control to further minimize safety impacts. The trade-offs between safety concerns and cost with respect to use of urea instead of ammonia at the alternative site would correspond to those at the primary site. For the same reasons set forth in Section III.C.2.c, above, the record does not establish that use of urea for NOx emission control at the alternative site would minimize environmental impacts consistent with the minimization of cost and other environmental impacts.

However, as noted in Section III.C.3.ix, above, the Company failed to provide modeling of the consequences of a release of aqueous ammonia at the alternative site. Accordingly, the Siting Board finds that the Company has not established that the environmental impacts of the proposed facility at the alternative site would be minimized with respect to safety, consistent with minimizing cost and other environmental impacts.

With respect to the comparison of the primary and alternative sites, the Siting Board has found: (1) that with use of water cooling at the alternative site, the primary site is preferable to the alternative site with respect to waterways/wetlands and EMF; (2) that the alternative site is preferable to the primary site with respect to land use, visual impacts, noise, and transportation; and (3) that the primary site and the alternative site are comparable with respect to air quality, water supply/wastewater, solid waste and safety.

The primary site was found to be preferable in two areas while the alternative site was found to be preferable in four areas. The primary site advantages stem from its accessibility to regional transmission lines and water supply intake/wastewater discharge locations on the Taunton River, avoiding the need for additional transmission line and water supply/wastewater line improvements and associated impacts. The alternative site advantages stem from the larger site size and availability of space separation and buffer from surrounding sensitive land use, as well as the avoidance of train passage through downtown Taunton.

Although the Siting Board has found the alternative site to be preferable to the primary site in four areas, we note that in Section III.C.2.c, above, the Siting Board required SCE to implement or further analyze measures to further mitigate the environmental impacts of the proposed facility at the primary site with respect to each such area. Specifically, the Siting Board found that, to allow approval of the primary site, SCE would be required to: (1) pursue agreements with Railroad Avenue property owners relative to a property value guarantee or other compensation program to further mitigate land use impacts; (2) pursue an off-site tree planting program to further mitigate visual impacts; (3) implement additional facility nighttime noise mitigation and provide plans for further mitigating daytime noise from idling locomotives;

and (4) provide plans for mitigating at-grade rail crossing concerns related to train passage through downtown Taunton.

With regard to the alternative site, the Siting Board notes that additional plans for water supply and wastewater lines would need to be reviewed to establish that environmental impacts would be minimized consistent with the minimization of cost and other environmental impacts. In addition, approval for the necessary new three-mile transmission line to serve the alternative site would require separate Siting Board review. We expect that more detailed plans addressing water supply and wastewater lines and transmission lines to serve the alternative site could identify additional mitigation for the environmental impacts of such facilities.

Although environmental impacts are likely to be further mitigated for the areas of primary concern at the respective sites, the primary site has been shown to be the more advantageous site in fewer areas than the alternative site.[488] Accordingly, the Siting Board finds that, on balance, the alternative site is preferable to the primary site with respect to environmental impacts.

In Section III.C.3.b, above, the Siting Board has found that the primary site is preferable to the alternative site with respect to cost. Thus, the Siting Board must balance the cost advantage of the primary site -- $7.5 Million to $11 Million, or significantly more if air cooling is required at the alternative site -- against the environmental advantages of the alternative site.

As discussed above, both sites offer important environmental advantages in different areas. Although the alternative site is preferable to the primary site in a number of areas based on its larger site size and generally greater buffer from residential areas, the record indicates the proximity of the Condominiums to the alternative site would pose some abutter concerns at the alternative site, albeit less severe than those at the primary site. Further, use of the

488 We note that the Siting Board has found that use of water cooling at the alternative site would be preferable to air cooling, but the record indicates that the Company may have to use air cooling at the alternative site. Such a possibility would result in the preferability of the primary site with regard to air quality impacts.

alternative site, like the primary site, would warrant attention to transportation impacts associated with passage of coal trains along secondary rail lines between Taunton and Framingham. Further, as mentioned above, the Siting Board has required SCE to implement or consider further mitigation in all of the environmental areas related to inadequate buffer and train passage through downtown Taunton, as part of any plan for the use of the primary site for the proposed facility.

Thus, the record establishes that, on balance, the environmental advantages of the alternative site are limited. At the same time, the $7.5 million to $11 million cost difference between the two sites is significant for a generating facility of the type and size proposed, and could be substantially larger if air cooling is required at the alternative site.

Accordingly, the Siting Board finds that the cost advantage of the primary site outweighs the limited environmental advantage of the alternative site. Therefore, the Siting Board finds that the primary site is preferable to the alternative site with respect to minimizing environmental impacts consistent with minimizing cost.

IV. DECISION

The Siting Board's enabling statute directs the Siting Board to implement the energy policies contained in G.L. c. 164, §§ 69H to 69Q, to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. G.L. c. 164, § 69H. In addition, the statute requires the Siting Board to determine whether plans for expansion or construction of energy facilities are consistent with 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 upon compliance with the condition regarding signed and approved PPAs, the Company will have 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, SCE will have established that its proposed project is reasonably likely to be a viable source of energy. In Sections III.B and III.C, above, the Siting Board has also found that SCE has considered a reasonable range of practical siting alternatives, and that with implementation of the listed conditions relative to air quality, land use, solid waste disposal, noise, visual impacts and transportation, the environmental impacts from the proposed facility at the primary site would be minimized consistent with minimizing cost. Finally, in Section III.C.3 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 with respect to minimizing environmental impacts consistent with minimizing costs.

Accordingly, the Siting Board finds that, upon compliance with the conditions set forth in Sections II.A.5, II.C, III.C.2, and III.C.3, above, and listed below, the construction and operation of the proposed project and ancillary facilities at the primary site will be consistent with providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. Further, as evidenced by the above discussions and analyses, the Siting Board agrees with the Company that the proposed project is consistent with various environmental protection and resource use and development policies of the Commonwealth.

Accordingly, the Siting Board APPROVES the petition of Silver City Energy Limited Partnership to construct a 169 megawatt bulk generating facility and ancillary facilities in Taunton, Massachusetts, subject to the following conditions.

(A) In order to establish that the proposed project will provide a necessary energy supply for the Commonwealth, and that its proposed project is financiable, the Company shall, within four years from the date of this conditional approval, submit to the Siting Board signed and approved PPAs which include capacity payments for at least 75 percent of the proposed project's electrical output and signed PPAs which include capacity payments with Massachusetts customers for at least 25 percent of the proposed project's electric output which are the result of a competitive resource solicitation process beginning in 1993 or beyond and which are approved pursuant to G.L. c. 164, § 94A.

(B) In order to ensure that the proposed project is viable, the Company shall provide to the Siting Board evidence of a steam sales agreement with an appropriate entity (CO_2 plant owner) prior to the commencement of construction.

(C) In order to establish that the proposed project is likely to be constructed on schedule and will be able to perform as expected, the Company shall provide the Siting Board with a signed EPC contract between SCE and BPC or a comparable entity as evidence of a reasonable assurance that the project is likely to be constructed on schedule and will be able to perform as expected.

(D) In order to establish that the proposed project has access to the regional transmission system, and therefore, will be capable of meeting performance objectives, the Company shall provide the Siting Board with a signed copy of an interconnection agreement between SCE and TMLP or other appropriate entity for evidence of the proposed project's access to the regional transmission system.

(E) In order to establish that the proposed project is likely to be operated and maintained in a manner consistent with reliable performance over the life of the power sales agreement, the Company shall provide the Siting Board with a signed copy of an O&M contract between SCE and COSI or comparable entity, for evidence the proposed project is likely to be operated and maintained in a manner consistent with reliable performance.

(F) In order to establish that its fuel acquisition strategy reasonably ensures a low-cost, reliable coal supply, the Company shall provide the Siting Board with (1) a signed copy of a coal contract between SCE and a coal supplier and any other contract(s) that may be necessary to address all significant provisions as those in the draft coal contract; and (2) a signed copy of a transportation contract.

(G) In order to establish that noise impacts would be adequately minimized, the Company shall provide an acceptable approach to accomplish additional noise mitigation such as to (1) reduce by at least an additional two dBA the calculated maximum daytime noise increases of ten dBA at the Railroad Avenue receptors during periods of on-site rail activity, and (2) to further address noise mitigation options for reducing noise impacts from idling locomotives, including the calculated nine dBA L_{90} increase at the Baker Road receptor and likely increases as may occur at any nearer residences in the vicinity of the proposed idling location.

(H) In order to establish that transportation impacts would be minimized, the Company shall provide the Siting Board with an acceptable approach to reduce the six-minute obstruction at grade crossings in downtown Taunton.

(I) In order to establish that the environmental impacts of the proposed facility at the primary site would be minimized with respect to solid waste, the Siting Board requires the Company to submit either (1) a signed agreement for the removal of ash, which includes provisions to ensure safe and environmentally acceptable removal thereof, or (2) a signed coal supply contract, which includes specific provisions to ensure safe and environmentally acceptable removal of the ash.

(J) In order to ensure that the proposed project is consistent with current zoning, the Company shall provide to the Siting Board evidence of either a D.P.U. zoning exemption approval or resolution of zoning appeals to the Company's advantage.

At such time as the Company provides the Siting Board with the information listed above, the Siting Board shall review the information and determine if the Company has complied with each condition. The Company will not receive final approval of its project until it complies with these conditions.

In addition, the Company shall comply with the following conditions during construction and operation of the proposed facility.

(K) In order to establish that the environmental impacts of the proposed facility at the primary site would be minimized with respect to air quality, the Company may use a maximum SO_2 emission rate of 0.225 lb/MMBtu and the other emission rates as described in Section III.C.2.a.i, above. Should the Company choose to propose an SO_2 offset plan consistent with the requirements for such a plan as set forth in the EEC (remand) Decision, as an alternative to maintaining an SO_2 emission rate of 0.225 lb/MMBtu or less, the Company shall submit to the Siting Board a plan to determine whether it meets said requirements and adequately minimizes air quality impacts, consistent with minimizing cost and other environmental impacts.

(L) In order to establish that land use impacts would be adequately minimized, it is appropriate for the Company to pursue agreements, in good faith, with the owners of the above-identified properties that will provide a limited degree of compensation or in effect an "abutter" property value guarantee program. To monitor compliance with this approach to minimization, the Company shall provide to the Siting Board copies of all such final agreements or a statement of reasons as to why one or more of such agreements is not forthcoming.

(M) In order to minimize the extent of calculated increases in noise from continuous sources at residential receptors, which exceed recognized noticeability thresholds, consistent with the minimization of cost, and to be consistent with the level of noise increase accepted in past reviews with similar circumstances, the Siting Board finds that it is appropriate for SCE to provide additional noise mitigation such as to reduce calculated maximum nighttime noise increases of nine dBA and ten dBA at two Railroad Avenue residential receptors by an additional two dBA.

(N) In order to establish that visual impacts would be minimized, the Company shall develop and implement an off-site tree planting plan that includes, as agreeable to affected landowners and affected local officials, plantings to help screen the proposed facility from Railroad Avenue and properties thereon east of the most westerly point of TMLP property frontage on Railroad Avenue, plantings to help screen the proposed facility from Somerset Avenue and properties thereon north of the TMLP access road and extending to the most northerly property abutting the TMLP property, and other plantings at locations within one-half mile of the active primary site. In implementing its tree planting plan, the Company: (1) shall provide tree plantings on private property only with the permission of the property owner, and in public ways only with the permission of the appropriate municipal officials; (2) shall provide written notice of this requirement to appropriate officials in Taunton and Berkley and to all affected property owners prior to commencement of construction; (3) may limit requests from local residents and City officials for tree plantings to no less than six months after initial operation of the plant; (4) shall complete all such requested plantings within one year after commencement of construction, or if a request after commencement of construction, within one year after such request; (5) shall be responsible for maintaining or replacing such plantings as necessary to ensure that health plantings become established.

In addition, the Siting Board notes that the findings in this decision are based upon the record in this case. A project proponent has an absolute obligation to construct and operate its facility in conformance with all aspects of its proposal as presented to the Siting Board. Therefore, the Siting Board requires the Company to notify the Siting Board of any changes other than minor variations to the proposal so that the Siting Board may decide whether to inquire further into a particular issue. The Company is obligated to provide the Siting Board with sufficient information on changes to the proposed project to enable the Siting Board to make these determinations.

Jolette A. Westbrook
Hearing Officer

Dated this 15th day of June, 1994

TABLE 1

RANGE OF REGIONAL NEED CASES (COMPANY ANALYSIS)
SURPLUS/(DEFICIENCY)
1997-2000

1997

Demand case	DSM	Low Supply	Base Supply	High Supply	Lowest Cont.	Highest Cont.
Ref	H	790	1420	1620	230	2172
Ref	B	108	503	703	668	1495
Ref	L	**(333)**	273	473	**(893)**	1025
Linear	H	**(788)**	**(192)**	250	**(1356)**	718
Linear	B	**(1676)**	**(1099)**	**(657)**	**(2244)**	(14)
GNP	H	**(1866)**	**(1293)**	**(851)**	**(2434)**	**(383)**
CAGR	H	**(2521)**	**(1961)**	**(1519)**	**(3089)**	**(1051)**
GNP	B	**(2754)**	**(2199)**	**(1757)**	**(3322)**	**(1086)**
Linear	L	**(2853)**	**(2301)**	**(1859)**	**(3421)**	**(1391)**
CAGR	B	**(3449)**	**(2866)**	**(2426)**	**(4017)**	**(1755)**
GNP	L	**(3931)**	**(3401)**	**(2959)**	**(4499)**	**(2491)**
CAGR	L	**(4626)**	**(4080)**	**(3628)**	**(5194)**	**(3160)**

1998

Demand case	DSM	Low Supply	Base Supply	High Supply	Lowest Cont.	Highest Cont.
Ref	H	68	685	885	**(542)**	1437
Ref	B	**(980)**	**(385)**	**(185)**	**(1590)**	607
Ref	L	**(1226)**	**(636)**	**(436)**	**(1836)**	116
Linear	H	**(1600)**	**(1018)**	**(576)**	**(2218)**	(108)
Linear	B	**(2403)**	**(1837)**	**(1395)**	**(3021)**	**(724)**
GNP	H	**(2889)**	**(2333)**	**(1891)**	**(3507)**	**(1423)**
CAGR	H	**(3640)**	**(3100)**	**(2658)**	**(4258)**	**(2190)**
GNP	B	**(3691)**	**(3153)**	**(2741)**	**(4309)**	**(2070)**
Linear	L	**(3728)**	**(3209)**	**(2767)**	**(4346)**	**(2299)**
CAGR	B	**(4443)**	**(3950)**	**(3478)**	**(5061)**	**(2807)**

Demand case DSM	Low Supply	Base Supply	High Supply	Lowest Cont.	Highest Cont.
GNP L	**(5016)**	**(4525)**	**(4083)**	**(5634)**	**(3615)**
CAGR L	**(5768)**	**(4292)**	**(4850)**	**(6386)**	**(4382)**

TABLE 1 (page 2)

RANGE OF REGIONAL NEEDS CASES (COMPANY ANALYSIS)
SURPLUS/(DEFICIENCY)
1997-2000

1999

Demand case	DSM	Low Supply	Base Supply	High Supply	Lowest Cont.	Highest Cont.
Ref	H	**(602)**	1	251	**(1212)**	803
Ref	B	**(1806)**	**(1228)**	**(978)**	**(2416)**	**(186)**
Ref	L	**(2071)**	**(1499)**	**(1249)**	**(2681)**	**(697)**
Linear	H	**(2239)**	**(1668)**	**(1162)**	**(2857)**	**(694)**
Linear	B	**(3034)**	**(2481)**	**(1975)**	**(3652)**	**(1304)**
GNP	H	**(3759)**	**(3221)**	**(2715)**	**(4377)**	**(2247)**
Linear	L	**(4467)**	**(3943)**	**(3437)**	**(5085)**	**(2969)**
GNP	B	**(4555)**	**(4033)**	**(3527)**	**(5173)**	**(2856)**
CAGR	H	**(4613)**	**(4093)**	**(3587)**	**(5231)**	**(3119)**
CAGR	B	**(5409)**	**(4905)**	**(4399)**	**(6027)**	**(3728)**
GNP	L	**(5988)**	**(5495)**	**(4989)**	**(6606)**	**(4521)**
CAGR	L	**(6482)**	**(6367)**	**(5861)**	**(7460)**	**(5393)**

2000

Demand case	DSM	Low Supply	Base Supply	High Supply	Lowest Cont.	Highest Cont.
Ref	H	**(1094)**	**(501)**	**(237)**	**(1704)**	315
Ref	B	**(2439)**	**(1874)**	**(1610)**	**(3049)**	**(818)**
Ref	L	**(2711)**	**(2152)**	**(1888)**	**(3321)**	**(1336)**
Linear	H	**(2987)**	**(2428)**	**(1922)**	**(3605)**	**(1454)**
Linear	B	**(3812)**	**(3270)**	**(2764)**	**(4430)**	**(2099)**
GNP	H	**(4762)**	**(4240)**	**(3734)**	**(5380)**	**(3260)**
Linear	L	**(5346)**	**(4836)**	**(4330)**	**(5964)**	**(3862)**
GNP	B	**(5587)**	**(5082)**	**(4576)**	**(6205)**	**(3905)**
CAGR	H	**(5722)**	**(5220)**	**(4714)**	**(6340)**	**(4246)**
CAGR	B	**(6547)**	**(6062)**	**(5556)**	**(7165)**	**(4885)**
GNP	L	**(7121)**	**(6648)**	**(6142)**	**(7749)**	**(5674)**

Demand case DSM	Low Supply	Base Supply	High Supply	Lowest Cont.	Highest Cont.
CAGR L	**(6482)**	**(6367)**	**(5861)**	**(7460)**	**(5393)**

Sources: Exhs. EFSC N-62; SCE-9, exhibit 5; EFSC-N-48.

Bold denotes deficiency of at least 150 MW.

TABLE 2

RANGE OF REGIONAL NEED CASES (STAFF ANALYSIS)
SURPLUS/(DEFICIENCY)
1997-2000

1997

Demand case DSM	Low Supply	Base Supply	High Supply
Ref H	979	1,496	2,002
Ref B	753	1,274	1,780
Ref L	384	891	1,397
Linear H	**(754)**	(47)	459
Linear B	**(1,642)**	**(950)**	**(444)**
GNP H	**(1,832)**	**(1,144)**	**(637)**
GNP B	**(2,720)**	**(2,046)**	**(1,540)**
GNP L	**(3,897)**	**(3,243)**	**(2,737)**
CAGR H	**(2,487)**	**(1,809)**	**(1,302)**
Linear L	**(2,819)**	**(2,148)**	**(1,641)**
CAGR B	**(3,415)**	**(2,712)**	**(2,206)**
CAGR L	**(4,592)**	**(3,919)**	**(3,403)**

1998

Demand case DSM	Low Supply	Base Supply	High Supply
Ref H	(4)	826	1,332
Ref B	**(262)**	565	1,071
Ref L	**(656)**	166	672
Linear H	**(1,504)**	**(695)**	**(190)**
Linear B	**(2,307)**	**(1,507)**	**(1,003)**

Demand case DSM		Low Supply	Base Supply	High Supply
GNP	H	**(2,793)**	**(1,999)**	**(1,495)**
CAGR	H	**(3,544)**	**(2,760)**	**(2,255)**
GNP	B	**(3,595)**	**(2,812)**	**(2,308)**
Linear	L	**(3,632)**	**(2,868)**	**(2,364)**
CAGR	B	**(4,347)**	**(3,573)**	**(3,068)**
GNP	L	**(4,920)**	**(4,173)**	**(3,669)**
CAGR	L	**(5,672)**	**(3,942)**	**(4,430)**

TABLE 2 (page 2)

RANGE OF REGIONAL NEED CASES (STAFF ANALYSIS)
SURPLUS/(DEFICIENCY)
1997-2000

1999

Demand case DSM		Low Supply	Base Supply	High Supply
Ref	H	**(686)**	244	810
Ref	B	**(1,023)**	(96)	370
Ref	L	**(1,445)**	**(521)**	45
Linear	H	**(2,088)**	**(1,169)**	**(603)**
Linear	B	**(2,883)**	**(1,972)**	**(1,406)**
GNP	H	**(3,608)**	**(2,703)**	**(2,137)**
Linear	L	**(4,316)**	**(3,416)**	**(2,850)**
GNP	B	**(4,404)**	**(3,505)**	**(2,939)**
CAGR	H	**(4,462)**	**(3,564)**	**(2,999)**
CAGR	B	**(5,258)**	**(4,366)**	**(3,801)**
GNP	L	**(5,837)**	**(4,949)**	**(4,383)**
CAGR	L	**(6,691)**	**(5,811)**	**(5,245)**

TABLE 2 (page 3)

RANGE OF REGIONAL NEED CASES (STAFF ANALYSIS)
SURPLUS/(DEFICIENCY)
1997-2000

2000

Demand case	DSM	Low Supply	Base Supply	High Supply
Ref	H	**(1,166)**	(126)	372
Ref	B	**(1,590)**	**(553)**	(55)
Ref	L	**(2,044)**	**(1,008)**	**(510)**
Linear	H	**(2,652)**	**(1,620)**	**(1,122)**
Linear	B	**(3,477)**	**(2,448)**	**(1,951)**
GNP	H	**(4,427)**	**(3,403)**	**(2,905)**
Linear	L	**(5,011)**	**(3,989)**	**(3,491)**
GNP	B	**(5,252)**	**(4,231)**	**(3,733)**
CAGR	H	**(5,387)**	**(4,367)**	**(3,869)**
CAGR	B	**(6,212)**	**(5,195)**	**(4,697)**
GNP	L	**(6,786)**	**(5,771)**	**(5,274)**
CAGR	L	**(7,746)**	**(6,735)**	**(6,238)**

NOTES: Table 2 incorporates the following changes from Table 1: (1) Reserve margins for the base and high supply case adjusted as follows: 22 percent in 1997, 21.5 percent in 1998, 21 percent in 1999 and 20.5 percent in 2000; (2) reference forecast high DSM case is the NEPOOL high DSM case; (3) reference forecast low DSM case is the NEPOOL reference forecast low DSM case; (4) reference forecast base DSM case discounts DSM increment over 1991 by 11.4 percent; (5) reference forecast high supply case includes uncommitted portion of MASSPOWER and Enron; (6) alternative demand forecast cases include 49 MW less supply in 1997, 13 MW more supply in 1998, 68 MW more supply in 1999, and 252 MW more supply in 2000.

Bold signifies deficiency of at least 150 MW.

SOURCES: Exhs. EFSC-N-48; EFSC-N-61A; EFSC-N-62; SCE-RR-6; SCE-9, attached exhibit 9.

TABLE 3

RANGE OF MASSACHUSETTS NEED CASES (COMPANY ANALYSIS)
SURPLUS/(DEFICIENCY)
1997-1998

1997

Demand case	DSM	Low Supply	Base Supply	High Supply	Lowest Cont.	Highest Cont.
Ref	H	**(920)**	**(288)**	(95)	**(712)**	(37)
Ref	B	**(1,088)**	**(456)**	**(263)**	**(880)**	**(205)**
Ref	L	**(1,238)**	**(605)**	**(413)**	**(1,030)**	**(356)**
EndYr	H	**(1,272)**	**(640)**	**(447)**	**(1,064)**	**(390)**
EndYr	B	**(1,385)**	**(753)**	**(560)**	**(1,177)**	**(503)**
ExVal	H	**(1,418)**	**(786)**	**(593)**	**(1,210)**	**(536)**
EndYr	L	**(1,474)**	**(842)**	**(649)**	**(1,266)**	**(591)**
ExVal	B	**(1,587)**	**(955)**	**(762)**	**(1,379)**	**(705)**
Linear Regr		**(1,603)**	**(971)**	**(778)**	**(1,395)**	**(721)**
ExVal	L	**(1,736)**	**(1,104)**	**(911)**	**(1,528)**	**(854)**
CAGR Regr		**(2,136)**	**(1,504)**	**(1,311)**	**(1,928)**	**(1,254)**

1998

Demand case	DSM	Low Supply	Base Supply	High Supply	Lowest Cont.	Highest Cont.
Ref	H	**(1,231)**	**(598)**	**(406)**	**(1,110)**	**(348)**
Ref	B	**(1,424)**	**(792)**	**(599)**	**(1,303)**	**(541)**
EndYr	H	**(1,533)**	**(901)**	**(708)**	**(1,412)**	**(650)**
Ref	L	**(1,593)**	**(961)**	**(768)**	**(1,472)**	**(710)**
EndYr	B	**(1,672)**	**(1,040)**	**(847)**	**(1,551)**	**(789)**
ExVal	H	**(1,740)**	**(1,108)**	**(915)**	**(1,629)**	**(857)**
EndYr	L	**(1,781)**	**(1,149)**	**(956)**	**(1,660)**	**(898)**
Linear Regr		**(1,815)**	**(1,183)**	**(990)**	**(1,694)**	**(932)**
ExVal	B	**(1,933)**	**(1,301)**	**(1,108)**	**(1,812)**	**(1,050)**
ExVal	L	**(2,103)**	**(1,471)**	**(1,278)**	**(1,982)**	**(1,220)**
CAGR regr		**(2,441)**	**(1,808)**	**(1,615)**	**(2,329)**	**(1,557)**

Bold signifies deficiency of at least 150 MW. Lowest contintency is attrition of existing utility units. Highest contingency is addition of planned but uncommitted NUGs.

SOURCES: Exhs. SCE-22, atts. RLC-10, RLC-12, RLC-15, RLC-16, RLC-17; SB-JH-RR-11R.

TABLE 4

RANGE OF MASSACHUSETTS NEED CASES (STAFF ANALYSIS)
SURPLUS/(DEFICIENCY)
1997-2000

1997

Demand case	DSM	Low Supply	Base Supply	High Supply
Ref	H	**(848)**	**(216)**	7
Ref	B	**(920)**	**(288)**	33
Ref	L	**(1,142)**	**(510)**	**(287)**
EndYr	H	**(1,173)**	**(541)**	**(318)**
EndYr	B	**(1,244)**	**(612)**	**(389)**
ExVal	H	**(1,345)**	**(713)**	**(490)**
EndYr	L	**(1,350)**	**(718)**	**(495)**
ExVal	B	**(1,417)**	**(785)**	**(562)**
Lin Regr		**(1,553)**	**(921)**	**(698)**
ExVal	L	**(1,639)**	**(1,007)**	**(784)**
CGR Regr		**(2,083)**	**(1,451)**	**(1,228)**

1998

Demand case	DSM	Low Supply	Base Supply	High Supply
Ref	H	**(1,099)**	**(467)**	**(244)**
Ref	B	**(1,185)**	**(553)**	**(330)**
EndYr	H	**(1,371)**	**(739)**	**(516)**
Ref	L	**(1,416)**	**(784)**	**(561)**
EndYr	B	**(1,457)**	**(825)**	**(602)**
EndYr	L	**(1,587)**	**(955)**	**(732)**
ExVal	H	**(1,605)**	**(973)**	**(750)**
ExVal	B	**(1,691)**	**(1,059)**	**(836)**
Lin Regr		**(1,711)**	**(1,079)**	**(856)**
ExVal	L	**(1,922)**	**(1,290)**	**(1,067)**
CGR Regr		**(2,331)**	**(1,699)**	**(1,476)**

TABLE 4 (page 2)

RANGE OF MASSACHUSETTS NEED CASES (STAFF ANALYSIS)
SURPLUS/(DEFICIENCY)
1997-2000

1999

Demand case DSM	Low Supply	Base Supply	High Supply
Ref H	**(1,368)**	**(736)**	**(465)**
Ref B	**(1,489)**	**(857)**	**(586)**
EndYr H	**(1,580)**	**(948)**	**(677)**
EndYr B	**(1,682)**	**(1,050)**	**(779)**
Ref L	**(1,731)**	**(1,099)**	**(828)**
EndYr L	**(1,837)**	**(1,205)**	**(934)**
ExVal H	**(1,855)**	**(1,223)**	**(952)**
Lin Regr	**(1,877)**	**(1,245)**	**(974)**
ExVal B	**(1,976)**	**(1,344)**	**(1,073)**
ExVal L	**(2,218)**	**(1,586)**	**(1,315)**
CGR Regr	**(2,591)**	**(1,959)**	**(1,688)**

2000

Demand case DSM	Low Supply	Base Supply	High Supply
Ref H	**(1,544)**	**(912)**	**(641)**
Ref B	**(1,709)**	**(1,067)**	**(796)**
EndYr H	**(1,770)**	**(1,138)**	**(867)**
EndYr B	**(1,889)**	**(1,257)**	**(986)**
Ref L	**(1,954)**	**(1,322)**	**(1,051)**
Lin Regr	**(2,018)**	**(1,386)**	**(1,115)**
EndYr L	**(2,070)**	**(1,438)**	**(1,167)**
ExVal H	**(2,092)**	**(1,460)**	**(1,189)**

Demand case DSM	Low Supply	Base Supply	High Supply
ExVal B	**(2,247)**	**(1,615)**	**(1,344)**
ExVal L	**(2,502)**	**(1,870)**	**(1,599)**
CGR Regr	**(2,835)**	**(2,203)**	**(1,932)**

NOTES: Table 4 incorporates the following changes from Table 3: (1) reserve margins adjusted for all supply cases as in Table 2; (2) high DSM case is NEPOOL high DSM case; (3) low DSM case is NEPOOL low DSM case; (4) reference DSM case discounts DSM increment over 1991 by 8.4 percent; and (5) high supply case includes uncommitted portion of MASSPOWER and Enron. **Bold** signifies deficiency of at least 150 MW.
SOURCES: Exhs. SCE-22; HO-JH-RR-11R; EFSC-N-61A at 1; SCE-RR-6S at 32.

TABLE 5

EMISSIONS OF CRITERIA POLLUTANTS AND CO_2

lb/MMBtu

Tech.	Heat rate	NOx	SO_2	CO	VOC	PM-10
TEC	9,800	0.15	0.23[1]	0.13	0.006	0.018
NGCC	8,553	0.022	0.0055	0.021	0.0023	0.0032
GOCC	8,553	0.068	0.052	0.056	0.0075	0.039
CGCC[2]	9,033	0.186	0.4	0.064	0.01	0.01
PC	10,036	0.17	0.23	0.05	0.006	0.018
RO	9,359	0.15	0.11	0.031	0.005	0.018

TPY

Tech.	NOx	SO_2	CO	VOC	PM-10	CO_2[3]
TEC	853	1,308	740	34	102	1,150,000
NGCC	112	28	107	12	17	593,127
GOCC	154	71	139	17	50	
CGCC[2]	918	1,975	316	49	49	1,196,307
PC	949	1,284	280	34	100	1,196,307
RO	810	594	162	28	97	

NOTES:

1 Based on coal with a sulfur content equal to or less than 1.8 percent.

2 Based on data provided by SCE for the Martin project.

3 CO_2 emissions based on 85 percent plant availability for all technologies. CO_2 emissions for the proposed facility do not relflect extraction of 50,000 tpy for CO_2 facility. CO_2 emissions for the technology alternatives are based on the following heat rates (1) 9,000 Btu/kWh for the NGCC alternative, and (2) 10,500 Btu/kWh for the CGCC and PC alternatives.

SOURCES: Exhs. EFSB-RR-142; SCE-23, app. A, Table 1, Table 3; AG-RR-13; EFSC-E-10.

TABLE 6

EMISSIONS OF CRITERIA POLLUTANTS AND CO_2
CFB/CGCC Alternatives

lb/MMBtu

Technology	Heat rate	NOx	SO_2	CO	VOC	PM-10
TEC	9,800	0.15	0.23	0.13	0.006	0.018
CGCC (provided by EEC - based on Martin project)	9,033	0.186	0.4	0.064	0.01	0.01
CGCC (provided by EEC)	9,033	0.068	0.072	0.056	0.0075	0.039
CGCC (A.G. original)	9,872	0.12	0.03	0.09	0.006	0.0025
CGCC (A.G. update)	8,774					
CGCC (Wabash permit)	10,118	0.116	0.265	0.207	0.0023	0.00885

TPY

Technology	Heat rate	NOx	SO_2	CO	VOC	PM-10	CO_2
TEC	9,800	853	1,308	740	34	102	1,150,000
CGCC (provided by EEC - based on Martin project)	9,033	918	1,975	316	49	49	1,196,307
CGCC (provided by EEC)	9,033	369	350	304	41	21	
CGCC (A.G. original)	9,872	670	162	492	14	33	1,125,000
CGCC (A.G. update)	8,774						
CGCC (Wabash permit)	10,118						

SOURCES: Exhs. AG-9, Att. D; AG-RR-50; EFSB-RR-142; AG-5-44; JH-RR-1; AG-RR-13; EFSC-E-10

TABLE 7

PREDICTED CONTRIBUTIONS TO AMBIENT AIR QUALITY LEVELS
AS A PERCENTAGE OF NAAQS

Technology	NOx	SO_2			CO		PM-10	
	annual	3-hr	24-hr	annual	1-hr	8-hr	24-hr	annual
TEC	0.3	2.2	1.4	0.6	0.07	0.19	8.7	3.0
NGCC	0.3	0.06	0.11	0.13	0.01	0.03	0.13	0.10
GOCC	0.9	0.5	0.8	0.9	0.05	0.12	1.5	0.6
CGCC[1]	2.5	3.9	6.1	6.8	0.05	0.1	0.4	0.16
PC	8.5	7.9	12.5	14.3	0.06	0.06	2.3	1.8
RO	7.0	3.5	5.6	6.4	0.03	0.02	2.2	1.8
NAAQS (micrograms per cubic meter)	100	1300	365	80	40,000	10,000	150	50

NOTES:

1 CGCC data provided by Company, based on Martin project.

SOURCES: Exhs. EFSB-RR-142; SCE-23, app. A, Table 5, Table 6.

TABLE 8
WATER USE/WASTEWATER DISCHARGE

Water Use (MGD)

Alternative Technology	Taunton River Use	City Water Use	Total	Consumptive Use
TEC-CFB	2.31	0.08	2.39	1.94
NGCC	1.15	0.26[1]	1.45	1.14
GOCC	1.15	0.28[1]	1.47	1.15
PC	2.31	0.21	2.52	1.97
RO	2.31	0.21	2.52	1.97
CGCC	1.15	0.36	1.65[2]	1.15

Wastewater Discharge (gpd)

Alternative Technology	Cooling Tower	Process Water	Total Discharge
TEC-CFB	433,400	15,120	448,520
NGCC	216,720	93,000	309,720
GOCC	216,720	98,900	315,620
PC	433,400	114,480	547,880
RO	433,400	114,480	547,880
CGCC	216,720	200,000	416,720

Notes: 1. Includes water conservation techniques -- recycling of boiler blowdown and water from equipment drains.
2. Includes 0.14 MGD for coal slurry make-up water.

Sources: Exh. AG-5-40 and att.

TABLE 9

LEVELIZED COSTS

Technology Parameters

	TEC	NGCC	GOCC	CGCC	PC	RO
HEAT RATE (Btu/kWh)	9800	8553	8553	9033	10036	9359
AVAIL. FACTOR (%)	85.0	86.8	86.8	88.2	81.4	84.7
CAPITAL COST ($/KW)	2064	1107	1107		3290	1936

20-yr Levelized Cost
1997 $/MWH

	TEC	NGCC[1]	NGCC[2]	GOCC[3]	GOCC[4]	GOCC[5]	CGCC	PC	RO
BASE	82.06	98.27	99.37	89.89	84.56	88.38	97.43	128.13	108.26
LOW INT	79.02	96.67		88.29		86.87	93.03	123.07	105.39
HI INT	85.33	99.99		91.60		111.64	102.16	133.57	111.33
LOW FUEL	79.45	91.44	92.43	83.90	79.11	102.21	94.90	125.31	102.71
HI FUEL	84.67	105.10	106.30	95.88	90.02	94.36	99.97	130.95	113.80

NOTES: 1,3 - SCE fuel forcast
2,4 - NGW fuel forecast
5 - SCE forecast and 92 % availability

TABLE 9 (Page 2)

30-yr Levelized Cost
1997 $/MWH

	TEC	NGCC[1]	NGCC[2]	GOCC[3]	GOCC[4]	GOCC[5]	CGCC	PC	RO
BASE	84.28	107.15	108.44	101.59	95.27	100.08	100.78	139.22	121.95
LOW INT	81.54	105.71		100.15		98.72	96.80	134.64	119.37
HI INT	87.23	108.70		103.14		101.55	105.04	144.13	124.73
LOW FUEL	81.45	99.50	100.66	94.49	88.80	92.99	97.93	136.05	115.37
HI FUEL	87.11	114.80	114.80	116.22	101.73	107.18	103.62	142.38	128.54

40-yr Levelized Cost
1997 $/MWH

	TEC	NGCC[1]	NGCC[2]	GOCC[3]	GOCC[4]	GOCC[5]	CGCC	PC	RO
BASE	86.58	114.95	116.40	111.76	104.61	110.23	104.61	151.32	134.97
LOW INT	83.93	113.56		110.37		108.91	100.78	146.91	132.47
HI INT	89.43	116.45		113.25		111.64	108.73	156.05	137.64
LOW FUEL	83.59	106.62	107.92	103.74	97.31	102.21	101.53	147.90	127.52
HI FUEL	89.57	123.29	124.88	119.78	111.91	118.24	107.69	154.74	142.41

NOTES: 1,3 - SCE fuel forcast
2,4 - NGW fuel forecast
5 - SCE forecast and 92 % availability

SOURCES: Exhs. EFSB-RR-154; EFSB-AER-33; AG-44; SCE-22.

Unanimously APPROVED by the Energy Facilities Siting Board at its meeting of June 13, 1994 by the members and designees present and voting. Voting for approval of the Tentative Decision as amended: Kenneth Gordon (Chairman, EFSB/DPU); Barbara Kates-Garnick (Commissioner, DPU); Mary Clark Webster (Commissioner, DPU); Stephen Remen (for Gloria C. Larson, Secretary of Economic Affairs); Andrew Greene (for Trudy Coxe, Secretary of Environmental Affairs); Joseph Faherty (Public Member); and William Sargent (Public Member).

Kenneth Gordon
Chairman

Dated this 15th day of June, 1994

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).