# Decision and Orders

Massachusetts Energy Facilities Siting Council

# VOLUME 25

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COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

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| In the Matter of the Petition of Berkshire Gas Company for Approval of its Application to Construct a 6.2 Mile, 12-Inch Diameter, Natural Gas Pipeline with Maximum Operating Pressure of 500 Pounds Per Square Inch and Related Meter Station | EFSC 91-29 |

FINAL DECISION

Robert W. Ritchie
Jolette A. Westbrook
Hearing Officers
June 26, 1992

On the Decision:

Phyllis Brawarsky

APPEARANCES: James M. Avery, Esq.
Michael F. Donlan, Esq.
James H. Keshian, Esq.
Rich, May, Bilodeau & Flaherty
The Old South Building
294 Washington Street
Boston, MA 02108
FOR: Berkshire Gas Company
Petitioner

John A. DeTore, Esq.
Ellen W. Schmidt, Esq.
Keohane, DeTore & Keegan
21 Custom House Street
Boston, MA 02110
FOR: Altresco Pittsfield, L.P.
Intervenor

Jeffrey M. Bernstein, Esq.
Bernstein, Cushner & Kimmell, P.C.
One Court Street
Suite 700
Boston, MA 02108
FOR: Town of Richmond
Intervenor

Eric S. Biss
City Council, Ward 3
City of Pittsfield
62 Revere Parkway
Pittsfield, MA 01201
Pro Se
Intervenor

Shirley Motyl-Clerici
Ronald Clerici
633 Tamarack Road
Pittsfield, MA 01201
Pro Se
Intervenors

Zelda J. Brandon
56 Lillian Street
Pittsfield, MA 01201
Pro Se
Interested Person

Elizabeth B. Williams
274 William Street
Pittsfield, MA 01201
Pro Se
Interested Person

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APPENDIX:


Figure 1: Primary and Alternative Routes, Primary Meter Station Site

The Energy Facilities Siting Council hereby CONDITIONALLY APPROVES the petition of Berkshire Gas Company to construct: (1) a 6.2 mile, 12-inch diameter natural gas pipeline with a maximum operating pressure of 500 pounds per square inch along the proposed route described herein; and (2) a meter station at the proposed site as described herein.

# I. INTRODUCTION

## A. Summary of the Proposed Project and Facilities

The Berkshire Gas Company ("Berkshire" or "Company") distributes and sells natural gas to residential, commercial and industrial customers in 19 communities throughout Berkshire, Franklin, and Hampshire Counties. Berkshire Gas Company, 23 DOMSC 294, 298 (1991) ("1991 Berkshire Gas Decision"). In the split year 1989-1990, the Company had an average of 30,342 firm service customers. Id. Berkshire also sells gas to interruptible customers. The Company's total normalized firm sendout for the split-year 1989-1990 was 5,528 million cubic feet ("MMcf") Id.[1]

Berkshire receives pipeline gas and underground storage gas from the Tennessee Gas Pipeline Company ("Tennessee") at its Pittsfield, West Pittsfield, North Adams, Stockbridge, and Greenfield meter stations. Id. Berkshire also receives, under transportation agreements with Tennessee, pipeline gas from Boundary Gas Incorporated ("Boundary") and storage return gas from Penn-York Energy Corporation ("Penn-York") and Consolidated Gas Supply Corporation;[2] and supplemental liquified natural gas

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1/ One MMcf of natural gas equals roughly one thousand decatherms (MDth) or one billion British thermal units ("BBtu"). For purposes of this review, the Siting Council assumes that one MMcf is equivalent to one MDth and that one decatherm ("Dth") is equivalent to one thousand cubic feet ("Mcf").

2/ Storage return gas is a form of natural gas supply which has been removed and transported from large underground storage facilities. Berkshire's storage facilities are located

("LNG") from Bay State Gas Company and Distrigas of Massachusetts Corporation ("DOMAC"). Id. In addition, Berkshire has auxiliary propane facilities in Pittsfield, Stockbridge, North Adams, Greenfield and Hatfield. Id., at 2.

In its most recent review of Berkshire's long-range forecast, the Energy Facilities Siting Council ("Siting Council") approved Berkshire's sendout forecast and conditionally approved Berkshire's supply plan. Berkshire Gas Company, 19 DOMSC 247, 251, 321-322, 324-327 (1990) ("1990 Berkshire Decision (Phase I)").[3,4]

In the case currently before the Siting Council, the Company has proposed to construct natural gas pipeline facilities in the City of Pittsfield including (1) a 6.2-mile, 12-inch diameter natural gas pipeline with a maximum operating pressure of 500 pounds per square inch ("psi"), and (2) a meter station to provide for the receipt of gas volumes for transportation on the

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in Pennsylvania and New York. Such gas supplies typically are injected into storage during the summer off-peak season and consumed during the winter heating season.

3/ In the 1990 Berkshire Decision (Phase I), the Siting Council imposed two conditions on the Company (19 DOMSC at 321-322). The Company responded to these two conditions on July 11, 1990 and October 10, 1990. In a letter to the Company dated December 12, 1990, the Siting Council acknowledged that Berkshire had satisfied those conditions.

4/ The Company's forecast filing also requested approval to construct pipeline and meter station facilities. On January 30, 1990, the Hearing Officer in that proceeding severed the forecast portion of the filing from the facilities portion of the filing. The Siting Council issued its decision on the forecast portion of the filing on February 9, 1990. 1990 Berkshire Decision (Phase I), 19 DOMSC 247. The decision on the facilities portion of the filing was issued on March 16, 1990. Berkshire Gas Company, 20 DOMSC 109 (1990) ("1990 Berkshire Decision (Phase II)").

proposed pipeline (Exh. HO-2, pp. 4, 7).[5,6] Berkshire's proposed meter station would be located near the Bousquet ski area (hereinafter "Bousquet delivery point" or "Bousquet meter station") along a Tennessee lateral pipeline, the North Adams lateral, and directly adjacent to related metering facilities proposed by Tennessee (id., p. 8, Exh. HO-4, p. 2-3, HO-SC-AL-10, Exh. 1).[7] The proposed pipeline would extend from the Bousquet delivery point to existing interconnection facilities that connect the North Adams lateral to the Altresco-Pittsfield, L.P.,

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5/ The Company originally proposed to construct an approximately 11.2-mile natural gas pipeline within Richmond and Pittsfield ("Richmond Feedline") and a meter station in Richmond (Exh. HO-1, p. 1-2). The Company subsequently filed an amendment to its petition in which Berkshire proposed to construct the meter station in Pittsfield and a 6.2-mile natural gas pipeline which is approximately one-half the length of the original Richmond Feedline. For a discussion regarding the original and amended proposals, see Section I.B, below.

6/ Berkshire and Altresco-Pittsfield, L.P., are considering a financing structure whereby the proposed facilities would continue to be operated and maintained by Berkshire, but would be owned by an entity involving Altresco-Pittsfield, L.P., and a subsidiary of Tennessee (Exh. HO-O-1; Tr. 4, pp. 268-269). This financing arrangement has not been finalized (Exh. HO-O-1).

7/ Berkshire indicated that the Tennessee portion of the meter station facilities would consist of two buildings -- a data acquisition telemetry facility and a metering facility -- and a 150 foot-long, eight-inch diameter pipeline that would interconnect the meter station facilities with the North Adams lateral (Exh. HO-2, pp. 8-9). Berkshire indicated that the Federal Energy Regulatory Commission ("FERC") has approved the application of Tennessee to construct and operate the facilities (Exh. H-E-52). Berkshire further indicated that a zoning exemption from the Massachusetts Department of Public Utilities ("DPU") is required prior to the commencement of construction by Tennessee and that Tennessee's request for a zoning exemption is pending before the DPU (Exh. HO-E-51).

cogeneration facility ("Altresco facility") (Exh. HO-2, pp. 4-5).[8] In addition, the Company proposes to construct a 12-inch diameter pipeline, approximately 2,600 feet in length with a maximum operating pressure of 100 psi, which would connect the Altresco facility with Berkshire's distribution system in Pittsfield ("backfeed line") (Exh. HO-1, p. 3-3).

The Siting Council previously approved the petition of Altresco-Pittsfield, Inc. to construct a 156 megawatt combustion turbine, combined cycle cogeneration facility in Pittsfield. Altresco-Pittsfield, Inc., 17 DOMSC 351 (1989) ("Altresco Decision"). The primary fuel for the Altresco facility is natural gas although the facility is capable of burning distillate oil. Id., 17 DOMSC at 254. The Altresco facility commenced commercial operations on September 1, 1990 (Exh. HO-1, p. 3-1). Natural gas is currently transported to the Altresco facility, on an interruptible basis, via the existing North Adams lateral and existing interconnection facilities (id., p. 3-2, Exh. AP-1, pp. 8-9). Berkshire's proposed pipeline and meter station will be capable of transporting on a firm basis, up to 45,000 Mcf per day of natural gas including 40,000 Mcf per day for the Altresco facility and 5,000 Mcf per day for Berkshire's system needs (Exh. HO-1, p. 3-3).[9]

The Company identified two routes for the proposed

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8/ The interconnection facilities consist of (1) a 12-inch diameter, approximately 2,600, foot Tennessee pipeline that extends from the North Adams lateral to a temporary Berkshire meter station ("Tenneco Interconnect"), and (2) a 12-inch diameter, approximately 2,500 foot, Berkshire pipeline that extends from the temporary Berkshire meter station to the Altresco facility ("Altresco spur line") (Exh. HO-1, pp. 3-7, 3-8). For a further discussion of the interconnection facilities, see Section II.A.3.b, below.

9/ The Company indicated that gas transported through the proposed pipeline for Berkshire's system needs would be delivered to Berkshire's distribution system via the backfeed line (Exh. HO-1, p. 3-3).

pipeline, the primary route and the alternative route (id., pp. 1-1, 1-2 n.16, 5-7, 5-8 n.26, 5-30, Exh. HO-2, pp. 7 n.9, p. 11).[10] The primary route would begin at the Bousquet delivery point in Pittsfield and travel to the east and north, within the public way and across private and public property, including the Bousquet ski area, the Pittsfield Country Club, Massachusetts Audubon Society's Canoe Meadows Wildlife Sanctuary ("Canoe Meadows") and Brattlebrook Park, to the existing interconnection facilities (Exhs. HO-1, pp. 1-2 n.16, 5-7, 5-8, HO-2, p. 7). The primary route would parallel the existing Tennessee North Adams lateral right-of-way ("ROW") for approximately 3,700 feet (Exhs. HO-1, Figure 5-2, HO-E-10). The Company also identified several variations to segments of the primary route (Exh. HO-1, Figure 5-5). The alternative route also would begin at the Bousquet delivery point, but then would travel parallel to the existing Tennessee North Adams lateral ROW from the Bousquet ski area to the interconnection facilities with the exception of one portion of the route between the Bousquet ski area and Pittsfield Country Club where the alternative route would travel within the public way (id., Figure 5-4).[11]

B. Procedural History

On April 12, 1991, Berkshire filed its proposal to construct the Richmond Feedline.[12] This proposed pipeline

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10/ The pipeline route approved by the Siting Council in the 1990 Berkshire Decision (Phase II) was not included as an alternative route in the instant application. See Section III.C, below.

11/ A complete description of the primary and alternative routes and all variations is provided in Section III.B, below.

12/ The Richmond Feedline would begin at the Richmond meter station site and continue within a public way up to, and then parallel to the existing Tennessee North Adams lateral ROW, through the Town of Richmond to Knox Road in Pittsfield. It would then travel along Knox Road and Tamarack Road to the together with certain existing interconnection facilities would connect the transmission system of Tennessee with the existing Altresco facility located in Pittsfield.[13] In addition, the Company proposed to construct a new metering station with a preferred site in the Town of Richmond. The facility application also set forth one alternative pipeline route ("Conrail/Cloverdale"), and route segment variations to the primary route.

On July 25, 1991, the Hearing Officers issued a Notice of Adjudication and Public Hearing and directed the Company to publish and post the Notice in accordance with 980 CMR 1.03(2). A public hearing was held in the City of Pittsfield on August 27, 1991.

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Bousquet ski area. From there, it would follow the Company's primary route (see Section III.B.1., below).

13/ In the 1990 Berkshire Decision (Phase II), the Siting Council approved the Company's application to (1) construct a pipeline designed to provide gas transportation services to the Altresco facility in the City of Pittsfield, and (2) construct a new meter station on Dublin Road in Richmond (20 DOMSC at 102-105). The Town of Richmond and Zelda Brandon were intervenors in that proceeding and appealed the Siting Council's decision to the Supreme Judicial Court. The Company stated that during the pendency of this proceeding, it would not pursue development of the pipeline along the previously approved route (Exh. HO-1, p. 1-3). As of this date, the appeal is still pending. The route approved in the 1990 Berkshire Decision (Phase II) was for an 11.5 mile gas pipeline extending from the Tennessee main line in Richmond to the Altresco facility in Pittsfield (20 DOMSC 213-216). However, the Company stated that continued opposition of certain Richmond and Pittsfield officials and residents to the previously approved route could result in lengthy delays in the permitting process for that route (Exh. HO-1, p. 2-6). Specifically, the Company stated that it was unable to obtain legislative approval for the Brattlebrook Park crossing of the previously approved route (Tr. 2, pp. 166-168). Further, the Company stated that since the 1990 Berkshire Decision (Phase II), new opportunities have arisen with respect to pipeline routing including (1) the availability of certain private ROWS, and (2) opportunities to mitigate the incremental environmental impact of pipeline construction (Exh. HO-1, p. 2-7).

Petitions to intervene were filed by Altresco Pittsfield L.P., by its General Partner Altresco, Inc. ("Altresco"), Eric S. Biss ("Biss"), the Town of Richmond ("Richmond"), and a joint petition was filed on behalf of Shirley Motyl-Clerici and Ronald Clerici ("Motyl/Clerici").[14] Petitions to participate as an interested person were filed by Zelda J. Brandon ("Brandon") and Elizabeth B. Williams ("Williams"). On November 8, 1991, the Hearing Officers granted all of the petitions to intervene and both of the petitions to participate as an interested person.

On September 13, 1991, the Company amended its facility application to adopt the new primary route for the natural gas pipeline and the new preferred meter station site as defined herein (Exh. HO-2).[15,16]

The Siting Council conducted evidentiary hearings on February 7, 10, 11, 19, and 20, 1992. Berkshire presented five witnesses: Leslie H. Hotman, vice president of supply, rates, and planning for Berkshire, who testified regarding need issues; Stephen J. Wright, staff coordinator in the marketing development department for Tennessee, who testified regarding need issues; Robert M. Allessio, chief engineer for Berkshire, who testified regarding safety and cost issues; William Sterling Wall, from HMM

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14/ William and Carolyn French ("the Frenches") filed a motion on November 19, 1991 for late-filed intervention. At a prehearing conference held on that date, the motion was granted (November 19, 1991 Prehearing Conference, Tr., p. 11). On January 1, 1992, the Frenches filed a motion to withdraw from the proceedings which was granted by the Hearing Officers on February 10, 1992 (Tr. 2, p. 22).

15/ Based on the Company's amendment to its filing, the Siting Council does not review the Richmond Feedline in this proceeding.

16/ At the August 27, 1991 public hearing, the Company stated that it would amend its facility proposal to adopt the Bousquet Feedline as the new primary pipeline route and the Bousquet meter station as the preferred meter station site (Public Hearing Transcript, p. 15).

Associates, Inc. ("HMM"), who testified regarding site selection and environmental issues; and Herbert F. Zepp, president of Smith and Norrington Engineering Corporation, who testified regarding safety and cost issues. Altresco presented one witness: Barry Curtiss-Lusher, an energy consultant with EnerProbe Consulting, who testified regarding site selection and environmental issues. Motyl/Clerici presented one witness: Eric Biss, who testified regarding meter station sites.

The Hearing Officers entered 220 exhibits into the record, consisting primarily of information and record request responses.[17] Berkshire entered seven exhibits into the record; Altresco entered two exhibits; and Motyl/Clerici entered 57 exhibits.

The Company and Altresco filed a joint initial brief ("Berkshire/Altresco Initial Brief") on March 20, 1992. Initial briefs of Richmond ("Richmond Initial Brief"), Motyl/Clerici ("Motyl/Clerici Initial Brief"), and Williams ("Williams Initial Brief") were filed on March 27, 1992, April 13, 1992, and March 11, 1992, respectively. On March 11, 1992, Biss and Brandon filed a joint supplemental brief ("Biss/Brandon Supplemental Brief"). The Company and Altresco filed a joint reply letter ("Berkshire/Altresco Reply Letter") on April 17, 1992, and Richmond filed a reply letter ("Richmond Reply Letter") on April 22, 1992. Reply briefs were filed by Clerici ("Clerici Reply Brief") on March 16, 1992 and April 23,

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17/ On November 8, 1991, the Company filed a motion requesting the Siting Council to incorporate into this proceeding the evidentiary record from the 1990 Berkshire Decision (Phase II). Affidavits in support of the Company's motion were filed by Richmond, Biss, Brandon and Williams. At a prehearing conference held on November 19, 1991, the Hearing Officers ruled that only the portion of the record from the 1990 Berkshire Decision (Phase II) that pertains to the need for the jurisdictional cogeneration plant (the Altresco facility) would be incorporated into this proceeding (November 19, 1991 Prehearing Conference, Tr. p. 10).

1992, and Williams ("Williams Reply Brief") on April 23, 1992. Biss and Brandon filed a joint reply brief ("Biss/Brandon Reply Brief") on March 16, 1992.[18]

C. Jurisdiction

The Company's facility application is filed in accordance with G.L. c. 164, sec. 69H, which requires the Siting Council to ensure a necessary energy supply for the Commonwealth with minimum impact on the environment at the lowest possible cost, and G.L. c. 164, sec. 69I, which requires gas companies to obtain Siting Council approval for construction of proposed facilities at a proposed site before a construction permit may be issued by any other state or local agency.

The Company's proposal to construct a 6.2-mile pipeline operating at a pressure up to 500 psi falls squarely within the fifth definition of "facility" set forth in G.L. c. 164, sec. 69G:

> (5) any new pipeline for the transmission of gas having a normal operating pressure in excess of one hundred pounds per square inch gauge which is greater than one mile in length except restructuring, rebuilding, or relaying of existing transmission lines of the same capacity.

In addition, the Company proposes to construct a meter station and backfeed line. The third definition of "facility" set forth in G.L. c. 164, sec. 69G is pertinent in determining whether the meter station and backfeed line are jurisdictional facilities. In that third definition a facility is defined as:

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

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18/ On June 16 and 18, 1992, Motyl/Clerici submitted motions to reopen the record. In a Procedural Order dated June 25, 1992, the Hearing Officers denied these motions.

In Commonwealth Electric Company, 17 DOMSC 249, 263 (1988) ("1988 ComElectric Decision"), the Siting Council established a two-part standard for determining whether a structure is a facility under the third definition of facility set forth in G.L. c. 164, sec. 69G. In that case, the Siting Council determined that a structure is an ancillary facility if (1) the structure is subordinate or supplementary to a jurisdictional facility, and (2) the structure provides no benefit outside of its relationship to the jurisdictional facility. Id.

With regard to the proposed meter station, the meter station is subordinate to the proposed pipeline, and provides no benefit outside of its relationship to the proposed pipeline. Therefore, the meter station is a jurisdictional facility under the third definition of facility set forth in G.L. c. 169, sec. 69G and will be reviewed in this proceeding.[19]

With regard to the proposed backfeed line, the Company contemplates that this pipeline will transport supplies purchased by Berkshire from the Altresco facility to Berkshire's distribution system in Pittsfield (Exh. HO-E-53). Berkshire

19/ The Notice of Adjudication issued in this case referenced two meter station sites -- one in Richmond on Dublin Road and the Bousquet delivery point. Under the original proposal, both the Richmond Feedline and the alternate pipeline route would have originated from the Richmond meter station site. In addition, under the original proposal, the Company proposed construction of a shortened version of the Richmond Feedline originating at the Bousquet delivery point as part of a phased-in construction approach under which the Richmond Feedline would be constructed in two phases. The Company noted that if the second phase of the Richmond Feedline was to be constructed, the Company would file an application with the Siting Council (Tr. 3, pp. 226-231). Under the Company's amended proposal, the Company contemplates that the new primary route and the alternative route would both originate from the Bousquet delivery point in Pittsfield. The Siting Council reviews the site selection process for the Bousquet delivery point to ensure that the Company has not overlooked or eliminated a clearly superior alternative (see Section III.C., below).

stated that the backfeed line could provide benefits to Berkshire, irrespective of the proposed facilities (Exh. HO-6). However, the Company presented conflicting evidence regarding the availability of Altresco supplies for Berkshire without the proposed 6.2-mile pipeline. Berkshire first stated that the construction of the proposed pipeline would be required in order for Berkshire to purchase volumes from Altresco, and that, therefore, the backfeed line would not provide a benefit to the Company outside of its relationship to the proposed pipeline (Exh. HO-E-53; Tr. 1, pp. 180-182). However, Berkshire and Altresco also argued that certain benefits, such as Berkshire's right to purchase pipeline gas supplies from Altresco, could be negotiated even without the proposed facilities (Berkshire/Altresco Initial Brief, p. 29 n.27, ).[20]

The quantity of supplies that would be available to Berkshire from Altresco would likely be affected by whether the 6.2-mile pipeline was constructed. However, the Siting Council notes that, even if the 6.2-mile pipeline was not constructed, Berkshire and Altresco would not be precluded from entering into contractual arrangements for the transfer of available supplies, including the right of Berkshire to purchase supplies from Altresco, when available. Thus, the backfeed line could provide potential benefit to Berkshire outside of its relationship to the proposed 6.2-mile pipeline. Accordingly, the Siting Council finds that, for purposes of this review, the backfeed line is not a jurisdictional facility.

In accordance with G.L. c. 164, sec. 69H, before approving an application to construct facilities, the Siting Council requires applicants to justify facility proposals in three

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20/ Furthermore, as part of its demonstration of need for the proposed facilities, Berkshire assumed that additional pipeline supplies would be available from Altresco without the proposed pipeline, under one supply scenario (Exh. HO-RR-5, updated sup.).

phases. First, the Siting Council requires the applicant to show that additional energy resources are needed (see Section II.A, below). Next, the Siting Council requires the applicant to establish that its project is superior to alternative approaches in terms of cost, environmental impact, reliability and ability to address the previously identified need (see Section II.B, below). Finally, the Siting Council requires the applicant to show that its site selection process has not overlooked or eliminated clearly superior sites, and that the proposed site for the facility is superior to alternative sites in terms of cost, environmental impacts, and reliability of supply (see Section III, below).

## II. ANALYSIS OF THE PROPOSED PROJECT

### A. Need Analysis

#### 1. Standard of Review

In accordance with G.L. c. 164, sec. 69H, the Siting Council is charged with the responsibility for implementing energy policies to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

In carrying out this statutory mandate with respect to proposals to construct energy facilities in the Commonwealth, the Siting Council evaluates whether there is a need for additional energy resources to meet reliability or economic efficiency objectives.[21] The Siting Council, therefore, must find that additional energy resources are needed as a prerequisite to approving proposed energy facilities.

In evaluating the need for new energy facilities to meet reliability objectives, the Siting Council has evaluated 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 Council 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. Enron Power Enterprise Corporation, 23 DOMSC 1, 16-62 (1991) ("Enron"); Eastern Energy Corporation, 22 DOMSC 188, 203-275 (1991) ("EEC"); West Lynn Cogeneration, 22 DOMSC 1, 11-51 (1991) ("West Lynn"); Bay State

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21/ In this discussion, "additional energy resources" is used generically to encompass both energy and capacity additions, including, but not limited to, gas transmission lines, synthetic natural gas facilities, LNG facilities, propane facilities, gas storage facilities, energy or capacity associated with gas sales agreements, and energy or capacity associated with conservation and load management.

Gas Company, 21 DOMSC 1, 14-23 (1990) ("1990 Bay State Decision"); MASSPOWER, Inc., 20 DOMSC 301, 311-336 (1990)("MASSPOWER"); 1990 Berkshire Decision (Phase II), 20 DOMSC at 123-132; Boston Edison Company/Massachusetts Water Resources Authority, 19 DOMSC 1, 9-17 (1989) ("BECo/MWRA"); New England Power Company, 18 DOMSC 383, 393-403 (1989) ("1989 NEPCo Decision"); Braintree Electric Light Department, 18 DOMSC 1, 23-27 (1988) ("1988 Braintree Decision"); Altresco Decision, 17 DOMSC at 360-369; New England Electric System, 2 DOMSC 1, 9 (1977).

With regard to contingencies, the Siting Council has found that new capacity is needed in order to ensure that service to firm customers can be maintained in the event that a reasonably likely contingency occurs. New England Power Company, 21 DOMSC 325, 334-358 (1991) ("1991 NEPCo Decision"); Middleborough Gas and Electric Department, 17 DOMSC 197, 216-219 (1988) ("1988 Middleborough Decision"); Hingham Municipal Lighting Plant, 14 DOMSC 7, 14-18 (1986); Boston Edison Company, 13 DOMSC 63, 70-73 (1985) ("1985 BECo Decision"); Taunton Municipal Lighting Plant, 8 DOMSC 148, 154-155 (1982); Commonwealth Electric Company, 6 DOMSC 33, 42-44 (1981); Eastern Utilities Associates, 1 DOMSC 312, 316-318 (1977).

The Siting Council also has determined in some instances that utilities need to add energy resources primarily for economic efficiency purposes. The Siting Council has found that a utility's proposed energy facility was needed principally for providing economic energy supplies relative to a system without the proposed facility. Massachusetts Electric Company/New England Power Company, 13 DOMSC 119, 137-138 (1985) ("1985 MECo/NEPCo Decision"); Boston Gas Company, 11 DOMSC 159, 166-168 (1984) ("1984 Boston Gas Decision").

While G.L. c. 164, sec. 69H, requires the Siting Council to ensure an adequate supply of energy for Massachusetts, the Siting Council has interpreted this mandate to encompass not only evaluations of specific need within Massachusetts for new energy resources (1989 MECo/NEPCO Decision, 18 DOMSC at 396-403; 1988 ComElectric Decision, 17 DOMSC at 266-279; 1988 Middleborough Decision, 17 DOMSC at 216-219; 1985 BECo Decision, 13 DOMSC at 70-73), but also the consideration of whether proposals to construct energy facilities within the Commonwealth are needed to meet New England's energy needs. Turners Falls Limited Partnership, 18 DOMSC 141, 151-165 (1988) ("Turners Falls"); Altresco Decision, 17 DOMSC at 359-365; Northeast Energy Associates, 16 DOMSC 335, 344-354 (1987) ("NEA"); Massachusetts Electric Company/New England Power Company, 15 DOMSC 241, 273, 281 (1986); 1985 MECo/NEPCo Decision, 13 DOMSC at 129-131, 133, 138, 141. In so doing, the Siting Council has fulfilled the requirements of G.L. c. 164, sec. 69J, which recognizes that Massachusetts' generation and transmission system is interconnected with the region's and that reliability and economic benefits flow to Massachusetts from Massachusetts utilities' participation in the New England Power Pool ("NEPOOL").

Here, the Siting Council is presented with a proposal by a gas utility to construct a jurisdictional gas pipeline that would primarily transport gas to a cogeneration facility constructed by a non-utility developer. In addition, the pipeline would provide additional firm capacity for the Company to transport additional supplies to its firm customers. Therefore, the Siting Council must evaluate the need for the additional energy resources based on both goals of the proposed project.

The proposal to construct the cogeneration facility was approved by the Siting Council in the Altresco Decision, 17 DOMSC at 410. The Siting Council previously has approved proposals by gas utilities to construct a jurisdictional gas pipeline that would provide fuel transportation for a cogeneration plant developed by a non-utility entity. 1990 Bay State Decision, 21 DOMSC at 88; 1990 Berkshire Decision (Phase II), 20 DOMSC at 109.

The Siting Council also previously has approved a proposal by a gas pipeline that would provide a new fuel source to an existing generating plant owned by an electric utility. 1984 Boston Gas Decision, 11 DOMSC at 159. Further, the Siting Council has previously reviewed proposals by both electric companies and non-utility developers to construct jurisdictional electric transmission lines that would connect non-jurisdictional cogeneration plants to the regional transmission system. Turners Falls, 18 DOMSC at 195-196; 1989 NEPCo Decision, 18 DOMSC at 425.

In all such cases, whether the proponent is a utility or a non-utility developer, the proponent first must establish that the power from the generation facility is needed on either reliability or economic efficiency grounds. If it can be established that the generation facility is needed, the proponent then must show that the existing system is inadequate to support this new power source and that additional energy resources are necessary to accommodate the new power source. Turners Falls, 18 DOMSC at 153-164; 1989 NEPCo Decision, 18 DOMSC at 395. In applying this standard, the Siting Council emphasizes that our review of need is not limited to the need for a physical connection between the cogeneration plant and its fuel source or its end-users. To address the need issue in such cases so narrowly would be inconsistent with our statutory mandate.

The Siting Council also previously has approved proposals by gas companies to construct jurisdictional gas pipelines to serve load growth (1990 Bay State Decision, 21 DOMSC 1; Boston Gas Company, 17 DOMSC 155, (1988) ("1988 Boston Gas Decision")), and has approved a proposal by an electric company to construct a jurisdictional transmission line to ensure reliable supply to existing and future loads (1988 ComElectric Decision, 17 DOMSC at 249). In addition, the Siting Council previously has approved a gas company's proposal to construct a gas pipeline to provide economic energy supplies to its system. 1984 Boston Gas Decision, 11 DOMSC at 166-168.

Motyl\Clerici argue that the standard of review that should be applied in the instant case is whether the proposed facilities would have direct, quantifiable reliability or economic efficiency benefits to Berkshire's existing customers (Motyl/Clerici Initial Brief, p. 38). Motyl/Clerici argue that this was the standard applied in the 1984 Boston Gas Decision (id., pp. 37-38).

The Siting Council notes that this issue was previously raised by Richmond and discussed by the Siting Council in the 1990 Berkshire Decision (Phase II). In that Decision, the Siting Council found that although the benefits and risks to Boston Gas customers were considered in the 1984 Boston Gas Decision, the Siting Council did not require a separate showing of net benefits to Boston Gas' customers, independent of the showing of overall energy supply and environmental benefits, as a basis for approving the gas pipeline in that case (20 DOMSC at 125-128). Further, the Siting Council notes that Altresco will be paying for the pipeline, and therefore, there will be no direct economic cost to Berkshire's customers. Accordingly, the Siting Council rejects Motyl/Clerici's argument that direct, quantifiable reliability or economic efficiency benefits to existing customers must be shown to establish the need for the proposed pipeline.

2. Need for the Jurisdictional Cogeneration Plant

The Siting Council previously has found that the region needs the power from the Altresco facility and that Massachusetts is likely to receive reliability, economic efficiency, and environmental benefits from the additional energy resources produced by the Altresco facility. Altresco Decision, 17 DOMSC at 351. Accordingly, the Siting Council finds that the need for the additional energy resources from the Altresco facility has been established.

### 3. Need for Additional Pipeline Capacity

#### a. Standard of Review

As noted previously, Berkshire has proposed to construct natural gas pipeline facilities, primarily intended to transport gas owned by Altresco, a non-utility user, to the Altresco facility located in Berkshire's service area. In addition, the proposed pipeline would provide Berkshire with additional capacity to serve its existing firm customers.

The standard of review for need as applied in previous electric transmission and pipeline cases remains essentially unchanged in the instant case. The need for energy resources in the form of additional pipeline capacity hinges upon the adequacy of the Company's existing system to meet its current needs as well as future projected needs.

#### b. Description of the Existing System

Berkshire introduces gas into its distribution system from two types of facilities -- Tennessee's meter delivery stations and Berkshire's propane plants. Tennessee transports gas to Berkshire's service territory via its principal interstate pipeline supplying Massachusetts, the Tennessee main line. The Tennessee main line enters the Commonwealth from New York State, passes to the south of Pittsfield through the nearby towns of Richmond, Stockbridge and Lenox, and continues eastward to the Connecticut River Valley.

From a tap point on the Tennessee main line in Richmond, Tennessee's North Adams lateral extends northward through Pittsfield to North Adams (Exhs. HO-N-37, HO-MC-RR-2). There are three Berkshire meter stations located along the North Adams lateral -- the West Pittsfield, Pittsfield[22] and North Adams

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22/ The Pittsfield meter station is actually located approximately one-half mile to the west of the North Adams lateral (Exh. HO-N-37). In Pittsfield, in the vicinity of the Altresco facility, the North Adams lateral connects to a meter stations (Exh. HO-N-8). These meter stations serve the municipalities of Adams, North Adams, Williamstown, Cheshire, Clarksburg, Pittsfield, Lanesboro, Dalton, Stockbridge, Lenox and Lenoxdale (id.).[23,24]

The North Adams lateral consists of two parallel pipelines: (1) a 27-mile, six-inch diameter pipeline that extends from the Tennessee main line to the North Adams meter station; and (2) a ten mile, ten-inch diameter pipeline that extends from the Tennessee main line to the Pittsfield spur line (Exhs. HO-N-2, HO-MC-RR-2). In 1990, as part of its Northeast Expansion ("NOREX") project, Tennessee expanded the capacity of the North Adams lateral by increasing the length of the ten-inch pipeline to ten miles (Exhs. AP-1, p. 9, HO-MC-RR-2). Berkshire indicated that installation of the NOREX facilities provided (1) increased quantities of firm supply for the overall Berkshire system, and (2) increased delivery capabilities at the Pittsfield meter station (Exhs. HO-N-7, HO-N-37).

In Pittsfield, the North Adams lateral passes within 5,000 feet of the Altresco facility (Tr. 4, p. 40). The existing interconnection facilities travel from the North Adams lateral to

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four-inch diameter pipeline that extends to the Pittsfield meter station ("Pittsfield spur line") (id.). Tennessee has recently received approval from FERC to replace the existing four-inch pipeline with an eight-inch pipeline (Tr. 1, p. 43).

23/ Stockbridge, Lenox and Lenoxdale are also served by the Stockbridge meter station which is located on the Tennessee main line (Exh. HO-N-8).

24/ Berkshire operates two propane storage and injection facilities along the North Adams lateral in Pittsfield and North Adams (Exh. HO-N-37). The Pittsfield facility has a storage capacity of 28.1 MMcf and a maximum daily design capacity of 5.5 MMcf (id.). The North Adams facility has a maximum storage capacity of 23.4 MMcf and a maximum daily design capacity of 4.8 MMcf (id.).

the Altresco facility (Exhs. HO-1, pp. 3-7, 3-8, HO-N-37).[25]

c. Adequacy of the Existing System to Supply Altresco

i. Introduction

In the 1990 Berkshire Decision (Phase II), the Siting Council found that the capacity of the existing pipeline system, including the then-pending expansion of the North Adams lateral under the NOREX project, would be inadequate to accommodate Berkshire's system needs, anticipated growth, and the requirements of the Altresco facility (20 DOMSC at 130-131). Since the 1990 Berkshire Decision (Phase II), however, expansion of the North Adams lateral under the NOREX project and installation by Berkshire and Tennessee of the interconnection facilities has been completed (Exhs. HO-1, pp. 3-7, 3-8, AP-1, p. 9). Further, the Altresco facility commenced commercial operation in September 1990, and, since December 1990, has been receiving pipeline supplies via the expanded North Adams lateral and the interconnection facilities (id.). The Company acknowledged that transportation service to the Altresco facility

25/ Berkshire stated that the interconnection facilities were originally constructed as interim facilities for the Altresco facility (Exh. HO-1, pp. 3-7, 3-8). Berkshire stated that it constructed the Altresco spur line to connect the Altresco facility to a temporary Berkshire meter station (id.). The temporary meter station, in turn, was connected to the North Adams lateral via a four-inch diameter pipeline (id.). The Altresco spur line was originally used for providing transportation service to the Altresco facility for testing and start-up purposes. When the Tenneco Interconnect was constructed, and gas was transported on this 12-inch diameter pipeline rather than the 4-inch diameter pipeline, a volume of gas sufficient to operate the Altresco facility at full capacity could be delivered to the facility (id.). Berkshire stated that the interconnection facilities will continue to be utilized in conjunction with the proposed pipeline (id., p. 3-2 n.6).

via the existing pipeline facilities has not yet been interrupted[26] and further acknowledged that, assuming a delivery pattern proportional to the projected 1992-1993 winter season, there is adequate interruptible capacity on the North Adams lateral, much of the time, to serve the Altresco facility (Exh. HO-RR-11; Tr. 2, p. 67).[27] Nevertheless, Berkshire and Altresco asserted that, in the long term, in order to provide firm transportation of up to 40,000 Mcf to the Altresco facility, additional pipeline facilities are needed.[28] While the Siting Council's decision in the 1990 Berkshire Decision (Phase II) found that additional pipeline was needed, this finding was based on assumed use of the NOREX capacity in conjunction with existing facilities. In light of the actual use of such facilities to serve Altresco over the last two years, the Siting Council again must evaluate whether additional facilities are needed to

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26/ Berkshire noted that the 1990-1991 winter was 17 percent warmer than a normal winter and that the 1991-1992 winter, through January, was six percent warmer than normal (Tr. 1, pp. 53, 56).

27/ Altresco noted that although it had, in the past, been able to obtain more than 31,500 Mcf via the existing facilities, deliveries have been limited to 31,500 Mcf since November, 1991 (Tr. 2, p. 67).

28/ Altresco indicated that a maximum of 40,000 Mcf would be required for plant operation during a winter peak period and that the proposed project would have the capacity to transport, on a firm basis, 40,000 Mcf per day to the Altresco facility (Tr. 4, pp. 91-92, 95-96). Altresco also indicated that it has contracted for firm gas supplies with a Canadian supplier in the amount of 31,500 Mcf per day and that it has received all federal and Canadian approvals required for the import of such supplies (Tr. 1, pp. 21-22, Tr. 2, pp. 71-72). Altresco further indicated that 31,500 Mcf would be sufficient for summer peak periods and that requirements above 31,500 Mcf for winter peak periods would be met by interruptible supplies such as backhaul service from Distrigas in Boston (Tr. 4, pp. 95-96). In addition, Berkshire's witness, Mr. Wright, noted that Tennessee has completed construction of all main line facilities necessary to transport Altresco's firm volumes of 31,500 Mcf per day from the Canadian border to the North Adams lateral (Tr. 1, p. 21).

transport up to 40,000 Mcf, on a firm basis, to the Altresco facility.

The Siting Council most recently reviewed Berkshire's supply plans in its 1990 Berkshire Decision (Phase I). Berkshire's supply plan, in that review, provided for the continued use of existing resources, including: (1) pipeline gas supplied by Tennessee; (2) additional pipeline gas and peaking supplies transported by Tennessee; and (3) propane delivered by truck and stored in Berkshire's service territory. 1990 Berkshire Decision (Phase I), 19 DOMSC at 299-301. In that Decision, the Siting Council found that the Company's supply plan was adequate for the Company's projected sendout over the forecast period. Id. at 302-307.

Berkshire indicated that it has two sources of firm gas supply which are delivered by Tennessee to its meter stations along the North Adams lateral, (1) Tennessee CD-6 volumes, and (2) Penn-York storage volumes (Exh. HO-N-4).[29] With regard to the Tennessee CD-6 volumes, Berkshire stated that Tennessee is contractually obligated to provide Berkshire up to 25,572 Mcf per day of firm gas supplies, system-wide, under its CD-6 contract (id.).[30] Berkshire stated that the CD-6 contract also established a maximum daily quantity limit of CD-6 volumes that can be delivered to each Berkshire meter station

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29/ Berkshire indicated that it also has contracted for the delivery of Distrigas and Bay State volumes on the North Adams lateral on a best efforts transportation basis (Exh. HO-N-26). The Company indicated that maximum daily Distrigas volumes of 2,924 Mcf and maximum daily Bay State volumes of 3,899 Mcf can be delivered to any of the meter stations along the North Adams lateral (id.).

30/ Berkshire indicated that the Tennessee NOREX project had increased Berkshire's maximum daily quantities of gas supply under its CD-6 contract by 4,976 Mcf (Exh. HO-N-7).

(Exh. HO-N-26).[31] With regard to the Penn-York storage volumes, Berkshire stated that Tennessee is contractually obligated to provide Berkshire with firm transportation service of up to 2,423 Mcf per day of Penn-York storage gas for delivery at the North Adams meter station (id.).[32]

The Company indicated that, in order for Tennessee to comply with its service reliability standards, minimum pressure must be maintained at each meter station, and noted that meter station pressures are dependent, in turn, on the quantity and location of deliveries along the lateral (Exhs. HO-N-3, HO-N-23).[33] Thus, the quantity of gas that Berkshire can receive at each of its existing meter stations depends on contractual limitations, as well as the actual day-to-day quantities and related pressure effects of deliveries at the various meter

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31/ Berkshire indicated that a maximum daily quantity of 25,527 Mcf of CD-6 firm supplies can be delivered among Berkshire's meter stations as follows: (1) 11,998 Mcf at the Pittsfield meter station; (2) 11,030 Mcf at the North Adams meter station; (3) 4,873 Mcf at the West Pittsfield meter station; (4) 5,130 Mcf at the Stockbridge meter station; and (5) 8,713 Mcf at the Greenfield meter station (Exhs. HO-N-26, HO-N-30). Berkshire further indicated that the NOREX project increased the maximum daily CD-6 quantity limit at the Pittsfield meter station from 10,000 to 11,998 Mcf (Exh. HO-N-7). Berkshire further noted that at its request, Tennessee has requested authorization from FERC to increase the maximum daily limit in CD-6 volumes at the West Pittsfield meter station to 10,000 Mcf, without increasing total system-wide deliveries to Berkshire (Exh. HO-N-30; Tr. 1, p. 44).

32/ Berkshire explained that, upon nomination by Berkshire, Tennessee is obligated to deliver the maximum contracted CD-6 and Penn-York storage volumes to each of the meter stations and would be subject to severe penalties if it could not deliver the firm contracted supplies (Exh. HO-N-4; Tr. 2, p. 89).

33/ The Company indicated that other variables that would influence pressure along the lateral and meter stations include main line pressure, temperature of the gas, and pipeline diameter (Exh. HO-N-23).

stations along the lateral (Exh. NO-N-3; Tr. 1, pp. 75-78, 87-89).[34]

Berkshire stated that a minimum operating pressure of 350 psi must be maintained at the North Adams meter station (Exhs. HO-N-2, HO-N-9).[35] Berkshire further stated that the pressure at the Pittsfield meter station, where the ten-inch North Adams lateral pipeline ends, is the most important factor in determining the pressure at the North Adams meter station (Tr. 1, pp. 75-78, 87-88).[36]

Berkshire stated that the pressure at the Pittsfield meter station determines the amount of gas that can be delivered to the Altresco facility (Exh. HO-RR-10). The Company stated that, therefore, when deliveries at the North Adams meter station are low, and thus, high pressures at the Pittsfield meter station are not required to deliver volumes to North Adams, adequate volumes can be made available at the Pittsfield meter station for the Altresco facility (id.).

ii. Company's Position

Berkshire and Altresco asserted that the capacity of the

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34/ The Company noted that the NOREX facilities were designed in order to allow delivery of Berkshire's maximum contracted volumes of firm gas supply as far north toward the terminus of the lateral as might be required, while at the same time, maintaining proper pressure along the lateral which the Company stated would maximize its delivery flexibility along the pipeline (Exh. HO-N-3; Tr. 1, p. 59).

35/ Berkshire also stated that shifting deliveries to meter stations closer to the Tennessee main line would have a limited impact on increasing the pressure at the terminus of the six-inch North Adams lateral pipeline, the North Adams meter station (Tr. 1, pp. 75-76).

36/ Berkshire explained that in order to deliver maximum quantities to the North Adams meter station, the pressure at the Pittsfield meter station must be high, approximately 700 psi, but that lower pressures are adequate for smaller deliveries to the North Adams meter station (Exh. HO-RR-10).

North Adams lateral is insufficient to transport the Altresco volumes, on a firm basis, the entire distance from the Tennessee main line to the interconnection facilities, based on both contractual obligations and actual peak day requirements (Exhs. HO-N-9, HO-N-10, NO-N-37, HO-RR-10).[37,38]

In support of its assertion, the Company stated that 31,500 Mcf would reach the Altresco facility via the existing facilities -- the North Adams lateral and interconnection

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37/ Altresco stated that if transportation arrangements to the facility were not firm, project financing, power purchase contracts and fuel supply contracts would be jeopardized (Exh. AP-1, pp. 12-13).

38/ The Company also argued that since the Siting Council found in the 1990 Berkshire Decision (Phase I) that the quantity and allocation of supplies under the NOREX project contributed to a least-cost supply plan, the need for the proposed project may already have been decided by the Siting Council (Berkshire/Altresco Initial Brief, pp. 22-23 n.20) (19 DOMSC at 303). The Siting Council disagrees with Berkshire's assertion that the need for the proposed project was implicitly accepted by the Siting Council in Berkshire's previous forecast review. First, the Siting Council cannot find that the proposed facilities are needed based on the contracted allocations of firm supplies, including the NOREX volumes, without considering whether actual and forecasted sendout levels also support such a finding. Moreover, in its most recent review of the Company's supply plan, the Siting Council analyzed the NOREX project with respect to the Company's overall supply plan for its entire service territory rather than looking at the allocation of specific NOREX volumes to individual meter stations. The finding that the NOREX volumes (or any generic volumes) contributes to a least-cost supply plan, does not constitute a blanket determination of need in support of new pipeline facilities anywhere in a Company's service area. To support the construction of a new pipeline serving a portion of Berkshire's territory, a more detailed analysis of supply allocations by sub-territory would be required -- a level of detail beyond that in the Company's dispatch analysis for its overall territory. Therefore, the Siting Council's previous finding that the NOREX project contributed to the Company's least cost supply plan cannot support, by itself, a finding of need for additional facilities in the instant case. 1991 Berkshire Decision, 23 DOMSC at 308 n.12.

facilities -- only when Berkshire takes less than its full contractual entitlements at its meter stations along the North Adams lateral (Exh. HO-N-14).[39] The Company provided an analysis which demonstrated that, in order to deliver 31,500 Mcf to the Altresco facility via the existing facilities and the maximum contracted volumes of 11,998 Mcf to the Pittsfield meter station, Tennessee could deliver only 11,000 Mcf to the North Adams meter station, 2,394 Mcf less than the contracted amount of 13,394 Mcf (Exh. HO-N-33, sup.).[40] The Company provided an additional analysis which demonstrated that delivery of maximum daily contracted volumes of 13,394 Mcf to the North Adams meter station and 11,998 Mcf to the Pittsfield meter station, would allow delivery of only 13,000 Mcf to the Altresco facility via the existing facilities (Exh. HO-N-9).[41] Therefore, the Company indicated that if Berkshire's sendout requirements exceeded 11,000 Mcf at the North Adams meter station, assuming sendout of 11,998 Mcf at the Pittsfield meter station, service to the Altresco facility would be partially interrupted (Exh. HO-N-33, sup.).[42]

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39/ Berkshire indicated that Tennessee would require amendment of its contracts with Berkshire under a FERC abandonment proceeding to continue to deliver Altresco's volumes to the interconnection facilities (Exh. HO-RR-11; Tr. 1, p. 90).

40/ The 13,394 Mcf represent CD-6 and Penn-York storage volumes that can be delivered to the North Adams meter station (Exh. HO-N-26).

41/ See footnote 36, above, for an explanation of how the relationship between volume and pressure at the Pittsfield and North Adams meter stations affect the delivery to the Altresco facility.

42/ To help clarify the degree to which Berkshire's contracted volumes are actually needed, Berkshire provided projected peak day sendout for 1991-1992 through 1995-1996 (Exh. HO-N-27). Berkshire's projected peak day sendout for 1991-1992 is: (1) 14,313 Mcf at the Pittsfield meter station; (2) 10,830 Mcf at the North Adams meter station; and (3) 5,273 Mcf at the West Pittsfield meter station

The Company asserted that actual 1991-1992 peak day experience also supports the need for the proposed facilities (Exh. HO-RR-10). In support of its assertion, the Company provided the actual peak day sendout of pipeline gas by meter station on the system-wide peak day for 1991-1992 as follows:
(1) 3,888 Mcf at the West Pittsfield meter station;
(2) 11,681 Mcf at the Pittsfield meter station; and
(3) 10,238 Mcf at the North Adams meter station
(Exh. HO-RR-6).[43,44] The Company then provided a hypothetical sendout analysis based on sendout levels of 5,519 Mcf to the West Pittsfield meter station[45] and 11,998 mcf to the Pittsfield meter station, together with the delivery of 36,500 Mcf to the Altresco

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(Exh. NO-N-27). For 1995-1996, Berkshire's projected peak day sendout is: (1) 15,427 Mcf at the Pittsfield meter station; (2) 10,539 Mcf at the North Adams meter station; and (3) 5,685 Mcf at the West Pittsfield meter station (id.). Although Berkshire's contracted volumes differ from projected peak day sendout to the individual meter stations, including a projected sendout at the North Adams meter station of less than the contracted amount for all years from 1991 through 1996, Berkshire indicated that it would be unwilling to reduce its contracted volumes unless it determined that there was no future need for the CD-6 volumes (Tr. 1, p. 91). Berkshire asserted that the flexibility of supply, which results from the availability of contracted supplies that are in excess of current daily requirements, enhances the least-cost purchasing strategy of the Company (id.).

43/ In comparing the actual and projected 1991-1992 peak sendout for Berkshire's service areas on the North Adams lateral, the Siting Council notes that the actual peak was 25,807 Mcf and the projected peak was 30,416 Mcf (see footnote 42, above) (Exhs. HO-RR-6, HO-N-27).

44/ The Company indicated that none of the 10,300 Mcf of propane capacity in Pittsfield and North Adams was utilized to meet sendout requirements on this peak day (Exh. HO-RR-6).

45/ The Siting Council notes that delivery of 5,519 Mcf, which is above the current contracted limit of 4,873 Mcf, assumes that Tennessee receives FERC authorization of its request to increase CD-6 delivery at the West Pittsfield meter station (see footnote 31, above).

facility via the existing facilities (Exh. HO-RR-10).[46] The Company maintained that this hypothetical sendout allocation reflects a realistic sendout pattern because: (1) the West Pittsfield delivery corresponds to the projected 1992-1993 winter peak day sendout of 5,273 Mcf; (2) the Altresco delivery reflects facility requirements; and (3) the Pittsfield delivery of the maximum contracted volumes was nearly surpassed by the actual 1991-1992 peak-day requirements (id.; Exhs. HO-N-27, HO-RR-6). The Company stated this hypothetical sendout analysis demonstrated that sendout to the North Adams meter station would be restricted to 10,069 Mcf -- a level insufficient to meet the actual 1991-1992 peak-day sendout of 10,238 Mcf (Exh. HO-RR-10).

iii. Arguments of the Intervenors

Motyl/Clerici argue that the Company's determination of need for the pipeline facilities is based on contractual requirements that can be changed by a FERC proceeding (Motyl/Clerici Initial Brief, pp. 6, 19, 34). Further Motyl/Clerici argue that if contractual agreements were amended to decrease the maximum amount of gas that could be delivered to certain meter stations along the North Adams lateral, adequate volumes could be made available for the Altresco facility, thus eliminating the need for the proposed project (id.). In addition, Motyl/Clerici argue that if the Company's analysis of delivery patterns reflected increased volumes for the West Pittsfield meter station, the proposed meter station could be sited closer to the Altresco facility, possibly as close as the existing Pittsfield meter station (id., p. 6).

iv. Analysis

The record in this case demonstrates that, assuming

46/ The 36,500 Mcf represents an amount less than the Altresco facility's peak day requirement of 40,000 Mcf.

delivery of maximum contracted volumes at the North Adams and Pittsfield meter stations, existing capacity on the North Adams lateral is inadequate for the firm transportation of Altresco supplies. However, in comparing the maximum contracted supplies to projected peak day requirements, the record also demonstrates that the maximum contracted supplies for the North Adams meter station are in excess of the Company's projected peak day sendout through at least the winter of 1995-1996. In addition, the Company's analyses show that, assuming delivery of as much as 11,000 Mcf of the 13,394 Mcf of contracted volumes to North Adams, Altresco can be supplied via the existing facilities.

While the availability of contracted allocations of pipeline supplies at particular points along a lateral may increase a Company's supply flexibility, the Siting Council cannot approve construction of a new pipeline based solely on a contracted sendout allocation. Thus, the contracted allocations of supplies, alone, do not demonstrate the need for the proposed facilities.[47]

The Siting Council notes, however, that the record indicates that, assuming Berkshire relies on pipeline supplies to the maximum extent before utilizing propane, the existing facilities currently are inadequate to meet peak day sendout requirements along the North Adams lateral while providing Altresco with a near peak daily delivery of 36,500 Mcf. Thus, the existing system is inadequate to provide firm delivery of

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47/ With regard to Motyl/Clerici's argument that a change in contracted allocation would eliminate the need for the proposed project, the Siting Council notes that a change in contracted allocation would not eliminate the need for the pipeline based on peak day pipeline gas requirements. With regard to Motyl/Clerici's argument that increased delivery at West Pittsfield would allow the meter station to be sited closer to the Altresco facility, the Siting Council notes that the pressure at the Pittsfield meter station is the most significant determinant of the amount of gas that can be delivered at the Altresco facility.

peak day requirements of 40,000 Mcf to the Altresco facility while meeting existing and projected Berkshire loads. Accordingly, the Siting Council finds that additional energy resources are needed for reliability purposes.[48]

d. Adequacy of the Existing System to Serve Berkshire

i. Company's Position

The Company stated that the proposed project would provide capacity and supply benefits to Berkshire's customers (Exh. HO-1, pp. 3-2, 3-3, 3-4). Berkshire indicated that contractual arrangements between Berkshire and Altresco provide for Berkshire's right to at least 5,000 Mcf per day of firm capacity in the proposed pipeline (id., p. 3-3). In addition, the contractual arrangements provide for Berkshire's right to purchase from Altresco (1) up to 7,500 Mcf per day, on peak days, throughout the winter ("peaking supplies"), and (2) back-up supplies of up to 31,500 Mcf per day in the event of proration or curtailment of firm gas supplies or firm pipeline capacity by Berkshire's suppliers or transporters ("surge protection") (id., p. 3-3; Exhs. HO-2 pp. 12-13, HO-N-12).[49] Berkshire asserted

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48/ The Siting Council notes that use of propane from Berkshire's facilities in Pittsfield and North Adams provides a theoretical means of offsetting this pipeline constraint. However, the use of propane to satisfy the demands placed on the system by Altresco deliveries would lead to cost and reliability impacts for Berkshire customers. Moreover, as discussed in Section II.A.3.d, below, the Company has provided additional analyses which demonstrate that, even with utilization of propane supplies, the existing system would be inadequate to serve the Altresco facility by 1995-1996 (Exh. HO-RR-5, sup.).

49/ Altresco indicated that peaking service and surge protection would be offered in exchange for certain balancing arrangements provided by Berkshire which would enable the Altresco facility to handle variations in its hourly takes (Exh. HO-SC-AL-14). Altresco also indicated that Berkshire's utilization of peaking service and surge protection volumes would that the pipeline supplies that would be available to Berkshire with the proposed project are a least-cost supply alternative and also enhance supply reliability (Exh. HO-RR-5). Berkshire stated that although its peak-day sendout could be met without the proposed project by dispatch of significant quantities of propane, this scenario would be unacceptable in terms of cost or reliability (id.; Exh. HO-RR-5, updated sup.).[50]

In support of its assertion, the Company stated that if propane were utilized instead of the proposed additional pipeline and peaking supplies, supply reliability would be compromised by 1995 because a sufficient reserve margin of at least 20 percent would not be maintained on the propane plants' daily design capacity (Exhs. HO-RR-5, HO-RR-5, sup.).[51] The Company asserted

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require the Altresco facility to operate with oil (Exh. HO-N-19). Berkshire indicated that, therefore, it could not utilize these volumes when the Altresco facility was prevented by environmental constraints from burning oil (Exh. HO-N-35).

50/ Berkshire and Altresco indicated that certain benefits such as Berkshire's right to purchase peaking supplies from Altresco could be negotiated without the addition of the proposed facilities (Berkshire/Altresco Initial Brief, p. 29 n.27). Berkshire provided an additional analysis of peak day sendout, without the proposed project, which demonstrated that if Altresco peaking supplies were utilized instead of propane, supply to the Altresco facility would be interrupted 17 times during the 1992-1993 winter and 30 times during the 1996-1997 winter (Exh. HO-RR-5, updated sup.).

51/ The Company indicated that, consistent with its peak day sendout forecast (see footnote 42, above), peak day propane sendout would be 6,545 Mcf in 1992 and increase to 7,646 Mcf in 1997 if no additional pipeline supplies were available to the Company (Exh. HO-RR-5, sup.). The Company stated that such peak day propane sendout would require two plants to operate at 79 percent and 85 percent, respectively, of their daily design capacity, thus failing to maintain a 20 percent reserve margin (id.). The Company also stated that during the 1995-1996 design winter, propane plants would be required to operate for 23 days and up to 14 consecutive days, whereas these plants are generally utilized for short-term or needle-peaking conditions on 12 to 15 days (id.). The Company added that it has not had to operate its propane plants at these capacities for these durations that a 20 percent reserve margin is a prudent planning standard based on a number of factors including the mechanical nature of the plants, age of the plants, and trucking delivery requirements (Exh. HO-RR-10).[52,53]

Berkshire indicated that, with the installation of the proposed project, sendout would be met almost entirely by pipeline gas (Exh. HO-RR-5, updated sup.).

ii. Arguments of the Intervenors

Motyl/Clerici assert that Berkshire has failed to demonstrate that its primary customers have a need for the proposed project (Motyl/Clerici Initial Brief, p. 6). Motyl/Clerici state that customer needs have been met by the

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(Exh. HO-RR-10).

52/ The Siting Council has not explicitly addressed the appropriateness of Berkshire's use of a 20 percent propane reserve margin as part of previous reviews of the Company's forecast. However, the Siting Council notes that, in its most recent review of Berkshire's forecast, Berkshire forecasted that its system-wide propane reserve margin under peak-day sendout would reach a forecast period low at 4.2 MMcf in 1989-90, representing 30 percent of its 13.8 MMcf peak day propane capability. 1990 Berkshire Decision (Phase I), 19 DOMSC at 330. For the following forecast year, Berkshire forecasted that its system-wide propane reserve margin would increase to 6.7 MMcf, or 49 percent of its propane capability, reflecting the addition of planned NOREX volumes. Id. Had Berkshire not provided for the addition of NOREX volumes in that year, its forecasted propane reserve margin would have dropped to 2.6 MMcf, or 19 percent of its propane capability -- just failing to meet the 20 percent standard on a system-wide level. Id.

53/ The Company noted that propane is less reliable and more expensive than pipeline gas and is the peaking source of last resort (Exh. HO-RR-10). The Company estimated that the cost for meeting a daily requirement consistent with 1995 peak day sendout would increase by $33,000 if the firm daily contracted requirements at the North Adams meter station were reduced by approximately 6,000 Mcf, thereby shifting reliance to propane (id.).

installation of the NOREX facilities which should address gas supply concerns for ten years (id., p. 36).

iii. Analysis

The record demonstrates that the existing facilities, with increased reliance on existing propane capacity, are adequate to meet the Company's own projected peak day sendout, as well as Altresco's delivery requirements, for the short term. However, the record further demonstrates that, even with increased reliance on existing propane capacity, Berkshire's existing energy resources would be inadequate to meet its peak day sendout starting in 1995-1996. Thus, the Company has established its customers' need for additional energy resources, based on reliability objectives, in 1995.

The Siting Council notes that typically, pipeline gas is a less expensive and more reliable energy supply relative to propane. The Siting Council also notes that delaying the proposed project until 1995 would require Berkshire to increase its reliance on propane until then, subjecting its customers to the higher risks and costs of such reliance. In light of the need for the pipeline in 1995 under any scenario, the benefits to Berkshire customers justify the construction of the proposed pipeline now, rather than in three years time. Accordingly, the Siting Council finds that the additional energy resources are needed to meet the needs of Berkshire's customers.[54]

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54/ Berkshire also argued that the pipeline was needed for economic efficiency reasons. The Siting Council notes that the Company failed to: (1) quantify the cost advantages of pipeline gas over propane; (2) estimate annual savings resulting from the use of pipeline gas rather than propane; and (3) relate the economic benefit of displacing propane to the more than six million dollar cost of the proposed project. In sum, the Company has not provided a clear and detailed quantifiable analysis of actual economic efficiency benefits that would be provided by the proposed project. While the Siting Council recognizes that economic efficiency benefits are likely to be derived from the proposed project, the Company has not demonstrated that the

B. Comparison of the Proposed Project and Alternative Approaches

1. Standard of Review

G.L. c. 164, sec. 69H, requires the Siting Council 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, sec. 69I, requires a project proponent to present "alternatives to planned action" which may include (a) other methods of generating, manufacturing, or storing, (b) other sources of electrical power or gas, and (c) no additional electrical power or gas.[55]

In implementing its statutory mandate, the Siting Council has required 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, and environmental impact. 1991 Berkshire Decision, 23 DOMSC at 314-322; 1991 NEPCo Decision, 21 DOMSC at 359-375; 1991 Bay State Decision, 21 DOMSC at 20; 1990 Berkshire Decision (Phase II), 20 DOMSC at 133-147; BECo/MWRA, 19 DOMSC at 18-30; 1989 MECo/NEPCO Decision, 18 DOMSC at 405-424; Turners Falls, 18 DOMSC at 161-173; 1988 Braintree Decision, 18 DOMSC at 25-27; 1988 ComElectric Decision, 17 DOMSC at 279-288; 1988 Middleborough Decision, 17 DOMSC at 219-144; Cambridge Electric Light Department, 15 DOMSC 187, 212-218 (1986) ("1986 CELCo Decision"): 1985 MECo/NEPCo Decision, 13 DOMSC at 141-183. The Siting Council has also required a petitioner to consider reliability of supply as part of its showing that its proposed project is superior to

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proposed project would provide guaranteed, economic benefits of a substantial magnitude given the cost and nature of the proposed project.

55/ G.L. c. 164, sec. 69I, also requires a petitioner to provide a description of "other site locations."

alternative approaches.[56]

2. Project Approaches

The Siting Council considers two project approaches to meet the identified need (1) the Company's proposed project, and (2) the alternative project approach of a Tennessee expansion of capacity of the North Adams lateral.

a. Berkshire's Proposed Project Approach

Berkshire's proposed project approach consists of (1) construction of the proposed meter station along the North Adams lateral to receive gas from Tennessee on behalf of Altresco and Berkshire, and (2) construction of the proposed 12-inch diameter pipeline between the meter station and existing pipeline facilities which interconnect to the Altresco facility (Exh. HO-2, pp. 4,7). The proposed project would provide Altresco with firm transportation of up to 40,000 Mcf per day to supply its cogeneration facility, and provide Berkshire with firm transportation of up to 5,000 Mcf per day to supply its Pittsfield market area (id.; Exh. HO-1, p. 3-3). The Company identified a primary route, alternative route and route segment variations to the primary route for the proposed project (see Section III, below).

b. Tennessee Alternatives

The Company indicated that it considered, in conjunction

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56/ In the 1989 MECo/NEPCo Decision, the Siting Council stated that in future facility proposal reviews, we would require a petitioner to consider reliability of supply as part of its showing that its proposed project is superior to alternative approaches (18 DOMSC at 412). The Siting Council has also stated that gas facility proposals differ significantly from electric facility proposals with respect to reliability, and that a comparison of the reliability of alternative approaches generally will not be applicable in gas facility reviews. 1990 Berkshire Decision (Phase II), 20 DOMSC at 133 n.10.

with Altresco and Tennessee, a Tennessee project to expand the capacity of the North Adams lateral as an alternative approach to meet the identified need (Exhs. HO-1, p. 3-11, HO-A-1). In order to provide firm deliveries of 31,500 mcf to the Altresco facility via the North Adams lateral to the interconnection facilities, the Company indicated that Tennessee would likely consider either (1) the replacement of the existing six-inch diameter pipeline with a 12-inch diameter pipeline for eight miles, beginning at the point of interconnection of the 6-inch diameter pipeline with the Tennessee mainline in Richmond ("replacement option"), or (2) the extension of the existing ten-inch diameter pipeline, north from Pittsfield, for approximately seven miles, parallel to the existing six-inch diameter pipeline ("extension option") (Exh. HO-A-1; Tr. 1, p. 100).[57] The extension option would begin at the interconnection point of the North Adams lateral and Tenneco Interconnect in Pittsfield and would travel in a northerly direction for seven miles through the communities of Pittsfield, Lanesboro, and Cheshire (Exh. HO-A-5). However, based on preliminary cost and reliability factors, but without an in-depth environmental analysis, the Company indicated that Tennessee's preferred approach would be the extension option (Exh. HO-A-1, sup.).[58] Thus, for purposes of this review, the Siting Council compares the proposed project with the extension option.

57/ Tennessee indicated that, in order to transport 45,000 Mcf along the North Adams lateral to the interconnection facilities, corresponding to the capacity of the proposed project, the extension option would need to be increased to 11.3 miles (Exh. HO-C-9).

58/ Tennessee noted that construction of the replacement option would be more costly due to costs associated with the removal of the existing pipeline and that the extension option would provide reliability benefits based on the additional length of dual pipeline capability (Tr. 1, pp. 103-104). Tennessee added that the regulatory approval framework would not differ for either of the options (id., pp. 104-105).

3. Ability to Meet the Identified Need

Before reviewing the proposed and alternative project approaches on the basis of cost and environmental impact, the Siting Council must determine whether the different project approaches are capable of meeting the identified need. 1988 Boston Gas Decision, 17 DOMSC at 169.

The Company stated that an analysis of volumes and pressures on the North Adams lateral established that Altresco volumes could be transported approximately 4.5 miles along the North Adams lateral, to the vicinity of the Bousquet Ski area, without impacting Tennessee's ability to transport Berkshire's maximum contracted volumes to the North Adams meter station and maintain minimum required operating pressures (Exh. HO-N-9; Tr. 1, pp. 94-95).[59] The Company further stated that the proposed project, in conjunction with the existing interconnection facilities -- the Tenneco Interconnect and the Altresco spur line -- would be capable of delivering 45,000 Mcf to Altresco and Berkshire at the appropriate pressure (Exhs. HO-N-2, pp. 1-4, 11-13, HO-N-10, HO-N-17; Tr. 3, p. 97).

Tennessee stated that the extension option would require FERC approval and that, based on its recent history of construction in the northeast, the FERC approval process would likely take from 2.5 to three years (Tr. 1, pp. 104-105).[60] Therefore, the Company asserted that, although the extension option could technically meet the need, it could not meet the need on a timely basis (Exh. HO-1, pp. 3-11, 3-12, 3-13). The Company noted that even if a filing had been submitted to FERC as

59/ The Company's analysis to determine the Bousquet delivery point is discussed in Section III.C, below.

60/ Berkshire indicated that the time-frame for a FERC permitting process could be lengthy due to potential intervention by groups that are concerned with national gas supply and rate issues (Tr. 2, pp. 105-106).

early as June 1990, the facilities would not be in place before 1994 (id., pp. 3-12, 3-13).

In the 1990 Berkshire Decision (Phase II), the Company also raised the issue of timeliness with regard to a Tennessee alternative (20 DOMSC at 136). In finding that the Tennessee approach could meet the identified need, the Siting Council stated that it would not attribute an advantage to Berkshire's proposed project relative to the Tennessee alternative merely because Altresco had elected not to pursue permitting for the Tennessee alternative. Id., at 137 n.17.

The Company asserted that it is appropriate for the Siting Council to consider timing in the instant case because the Company and Altresco began re-examining alternative project approaches subsequent to the date of the 1990 Berkshire Decision (Phase II) (Exh. HO-1, p. 3-12). In addition, Altresco maintained that its gas supply contracts, financing arrangements and power sales contract could be jeopardized if firm transportation was not in place by December 31, 1992 (Tr. 2, pp. 73-83, 93-98).[61]

With regard to the timing issue, Richmond argues that, unless the Siting Council finds that the current interim arrangements will provide adequate gas supplies to allow Altresco to meet its contractual commitments, the Siting Council must reject the Tennessee alternative due to the significantly greater

61/ Altresco asserted that FERC and National Energy Board of Canada approvals of its gas supply contracts were premised on firm transportation to the Altresco facility (Tr. 2, pp. 73-76). In addition, Altresco stated that its gas supply contract could be terminated by the supplier and then renegotiated at less favorable terms to Altresco if firm transportation was not in place by December 31, 1992 (id., pp. 94-95). Altresco further stated that its transportation contract with Tennessee could be jeopardized if Tennessee could not charge rates consistent with firm transportation (id., p. 80). Altresco added that termination of gas supply or transportation contracts could lead to defaults under Altresco's financing arrangements and power sales agreements (id., pp. 96-98, Exh. AP-1, pp. 12-13).

time that it would take to design, permit and construct a Tennessee alternative (Richmond Initial Brief, p. 9).

In addition to the issue of timeliness, Berkshire and Altresco argued that the Tennessee alternative would not provide the economic benefits to Berkshire's customers that would be provided by the proposed project, including peaking service, the increased transportation capacity, surge protection and joint balancing of supply. (Berkshire/Altresco Initial Brief, p. 33).

The record demonstrates that both the proposed project approach and the Tennessee replacement and extension options are technically capable of meeting the identified need to provide firm transportation of gas supplies to the Altresco facility.

With respect to the arguments concerning timing, the Siting Council notes that, although Berkshire and Altresco considered alternative project approaches at an early date and discussed such approaches with Tennessee, alternative project approaches were not actively pursued by Berkshire or Altresco. Further, the Company failed to provide evidence in the record to determine whether an application which had been filed with FERC at the same time as the application was filed with the Siting Council would have had a significantly longer permitting timeframe. Finally, there is no evidence in the record that Altresco's supply and transportation contracts are certain to be terminated and could not be extended if firm transportation to the facility is not completed by December 31, 1992.

With regard to arguments of Berkshire and Altresco regarding the inability of the Tennessee extension option to provide economic efficiency benefits to Berkshire's customers, the record indicates that the extension option could be increased in its length in order to transport 45,000 Mcf, thereby providing Berkshire with the capacity to transport 5,000 Mcf on its own behalf. Further, there is no evidence in the record that other benefits, such as peaking supplies, and surge protection could not be negotiated between Altresco and Berkshire (see Section

I.C, above).

Accordingly, the Siting Council finds that the proposed project approach and the Tennessee extension option are capable of meeting the identified need.

4. Cost

The Company estimated that the cost of construction of the proposed project would range from $6,385,000 for the primary route to $7,940,000 for the alternative route (Exh. HO-C-1).[62] The Company indicated that such costs include: (1) engineering, design and planning; (2) construction and materials; (3) licenses, permits and approvals; (4) easements; and (5) miscellaneous and contingency (id.).[63]

The Company indicated that it did not anticipate actual costs to vary more than five percent from estimated costs because (1) the estimate includes costs of materials that have been procured and easements that have been negotiated, and (2) construction costs, in general, have not increased since the estimate was prepared (Tr. 1, p. 187).

Based on its 1990 costs to construct the NOREX facilities, Tennessee estimated that the cost to construct the extension option would be $6,700,000 (Exh. HO-A-1, sup.; Tr. 1, p. 102). Tennessee explained that this estimate includes costs of materials, construction and easements but does not include costs of permitting, environmental review, contingencies, AFDC, a compressor that would be required at the Altresco facility or adjustments due to inflation (Exh. HO-C-10; Tr. 1, pp. 102-103,

62/ To compare the costs of the proposed and alternative project approaches, the Siting Council uses the cost of the primary route as the cost of the proposed project. Since both project approaches would require meter stations, only the cost of the pipelines is compared.

63/ The Company noted that the miscellaneous and contingency category for the primary route includes $225,000 for allowance for funds during construction ("AFDC") (Exh. HO-C-8).

110-111). The Company noted that AFDC would increase costs by approximately seven percent, and that adjustments for inflation to 1991 and 1994 would increase costs by 2.5 percent and 4.5 percent, respectively (Exh. HO-C-10; Tr. 1, p. 111).[64] Finally, the Company noted that an increase in the length of the Tennessee extension option to 11.3 miles to transport 45,000 Mcf, would increase costs by approximately 7.5 million dollars (Exh. HO-C-9).

The record indicates that the cost estimate for the proposed project is complete and that the actual cost would likely be within five percent of the estimated cost. The record also indicates that the cost estimate for the extension option is highly speculative in that it was not based on detailed engineering or environmental analysis specific to this project. In addition, the cost estimate for the extension option is not complete in that it does not include the cost of a compressor, permitting, or contingencies.

The Siting Council notes that even if the cost of the proposed project were increased by five percent, increasing the cost to approximately $6,700,000, it would still be less costly than the seven-mile extension option, if adjusted for AFDC and inflation to 1991 dollars.

Based on the foregoing, the Siting Council finds that the Company's proposed project would be superior to the Tennessee extension option with regard to cost.

5. Environmental Impacts

The Company stated that, based on a preliminary evaluation of the environmental impacts of the extension option, the overall environmental impacts of the proposed project and the extension option would be comparable but that the extension

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64/ The Siting Council notes that the cost of this extension option would be approximately $7,300,000 if adjusted for AFDC and inflation to 1991 dollars.

option has the potential for greater impacts on the natural environment than the proposed project (Exhs. HO-A-5, HO-RR-24, pp. 1, 6-10).[65] The Company noted that impacts to wildlife would be comparable for both projects but that the extension option would impact a significantly greater amount of wetlands and forest resources, and slightly more water crossings than would the proposed project (Exh. HO-RR-24, pp. 8-9).[66]

In comparing the impacts of both projects to the human environment, the Company estimated that the extension option would be constructed within 100 feet of 60 residences while the proposed project would be constructed within 100 feet of 80 residences (id., p. 6). The Company added that the extension option would both cross and extend along roadways and would disrupt traffic on a greater number of roadways than would the proposed project (id., pp. 7-8). The Company noted that impacts to archaeological, historic and agricultural resources along the extension option had not been evaluated (id., pp. 6-9). Finally, the Company stated that the extension option would traverse populated areas and that the degree of community acceptance and concern regarding this project has not been evaluated (id., pp. 4, 8).

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65/ The Company provided only a general discussion of the environmental impacts of the seven-mile Tennessee extension option (Exhs. HO-A-5, HO-RR-24).

66/ The Company noted that the extension option would affect approximately 12 acres of wetland resources and 14 acres of forest resources while the proposed project would affect approximately six acres of wetland resources and seven acres of forest resources (Exhs. HO-RR-24, pp. 8-9, BGC-2, Attach. B, p. 8). In addition, the Company noted that the extension option would require twelve waterway crossings while the proposed project would require eleven waterway crossings (Exh. HO-RR-24, pp. 8-9). The Company further noted that in comparing the extension option with the replacement option, the replacement option would affect approximately 15 acres of wetlands and approximately twice the forest resources as the extension option (id., pp. 4-6).

The record indicates that the environmental analysis of the extension option was not nearly as comprehensive or detailed as the environmental analysis of the Company's proposed project. It did not include an evaluation of all potential environmental impacts and did not include an evaluation of the additional four miles of pipeline that would be required to transport an amount of gas comparable to the capacity of the proposed project. However, the Company's limited analysis of the extension option indicates that the extension option would likely have a greater impact on wetlands and forest resources than the proposed project and that, where evaluated, other impacts would likely be comparable to the proposed project. In addition, the Siting Council notes that, in general, the overall impacts of an 11-mile pipeline, by virtue of its greater length, would likely be greater than the overall impacts of a six-mile pipeline.

Accordingly, based on the foregoing, the Siting Council finds that the proposed project is superior to the Tennessee extension option with respect to environmental impacts.

### 6. Conclusions: Weighing Need, Cost, and Environmental Impacts

The Siting Council has found that: (1) the proposed project and the Tennessee extension option are capable of meeting the identified need; (2) the proposed project is superior to the Tennessee extension option with respect to cost; and (3) the proposed project is superior to the Tennessee extension option with respect to environmental impacts.

Accordingly, the Siting Council finds that the proposed project is superior to the Tennessee extension option.

## III. ANALYSIS OF THE PROPOSED AND ALTERNATIVE FACILITIES

### A. Standard of Review

G.L. c. 164, sec. 69I requires a facility proponent to provide information regarding "other site locations." In implementing this statutory mandate, the Siting Council requires the petitioner to show that its proposed facility 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.

In order to determine whether the facility proponent has shown that its proposed facilities siting plans are superior to alternatives, the Siting Council has required a facility proponent to demonstrate that it has examined a reasonable range of practical facility siting alternatives. 1991 Berkshire Decision (Phase II), 23 DOMSC at 323; Enron, 23 DOMSC at 121; EEC, 22 DOMSC at 314; West Lynn, 22 DOMSC at 77; 1991 NEPCo Decision, 21 DOMSC at 376; 1990 Bay State Gas Decision, 21 DOMSC at 44; MASSPOWER, 20 DOMSC at 371; 1990 Berkshire Decision (Phase II), 20 DOMSC at 148; BECo/MWRA, 19 DOMSC at 38-42; Turners Falls, 18 DOMSC at 175-178; 1988 Braintree Decision, 18 DOMSC at 31-40; Altresco Decision, 17 DOMSC at 387; NEA, 16 DOMSC at 381-409. In order to determine that a facility proponent has considered a reasonable range of practical alternatives, the Siting Council typically has required the proponent to meet a two-prong test. First, the facility proponent must establish that it has 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. 1991 Berkshire Decision, 23 DOMSC at 323; Enron, 23 DOMSC at 121; EEC, 22 DOMSC at 314; West Lynn, 22 DOMSC at 77; 1991 NEPCo Decision, 21 DOMSC at 376-377; 1990 Bay State Gas Decision, 21 DOMSC at 44-45;

MASSPOWER, 20 DOMSC at 373-374, 382; 1990 Berkshire Decision (Phase II), 20 DOMSC at 148-149, 151-156. Second, the facility proponent must establish that it has identified at least two noticed sites or routes with some measure of geographic diversity.[67] 1991 Berkshire Decision, 23 DOMSC at 323-324; Enron, 23 DOMSC at 122; EEC, 22 DOMSC at 122-123; West Lynn, 22 DOMSC at 77-78; 1991 NEPCo Decision, 21 DOMSC at 376-377; 1990 Bay State Gas Decision, 21 DOMSC at 44-45; MASSPOWER, 20 DOMSC at 371-372; 1990 Berkshire Decision, 20 DOMSC at 148; Turners Falls, 18 DOMSC at 175-178; 1988 Braintree Decision, 18 DOMSC at 31-40; 1988 ComElectric Decision, 17 DOMSC at 301-303; NEA, 16 DOMSC at 381-409.

Finally, in order to determine whether the facility proponent has shown that its proposed facilities are sited at locations that minimize costs and environmental impacts while ensuring supply reliability, the facility proponent must 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. 1991 Berkshire Decision, 23 DOMSC at 324; Enron, 23 DOMSC at 122; EEC, 22 DOMSC at 315; West Lynn, 22 DOMSC at 78; 1991 NEPCo Decision, 21 DOMSC at 377-379; 1990 Bay State Gas Decision, 21 DOMSC at 47;

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67/ When a facility proposal is submitted to the Siting Council, the petitioner is required to present (1) its preferred facility site or route, and (2) at least one alternative facility 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 Council's review. In reaching a decision in a facility case, the Siting Council can approve a petitioner's preferred site or route, approve an alternative site or route, or reject all sites and routes. The Siting Council, 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.

<u>MASSPOWER</u>, 20 DOMSC at 382; <u>1990 Berkshire Decision (Phase II)</u>, 20 DOMSC at 148; <u>BECO/MWRA</u>, 19 DOMSC at 38-42; <u>Turners Falls</u>, 18 DOMSC at 175-178.

## B. Description of the Proposed and Alternative Facilities

### 1. Proposed Facilities

Berkshire's proposal consists of (1) the Bousquet Feedline, an approximately 6.2-mile, 12-inch diameter gas distribution pipeline to be operated at a maximum pressure of 500 psi (Exh. HO-2, p. 7), and (2) the Bousquet delivery point, a new meter station to be located near the Bousquet ski area in western Pittsfield along the North Adams lateral, and directly adjacent to metering facilities proposed by Tennessee (<u>id.</u>, pp. 4-8).

The primary route for the Bousquet Feedline begins at the site of the Bousquet delivery point, south of Tamarack Road and west of Dan Fox Drive, in Pittsfield (<u>id.</u>, p. 8, Exh. HO-E-23). The pipeline would travel parallel to the northern side of the North Adams lateral through the Bousquet ski area, would cross under the ski area parking lot and Dan Fox Drive and continue in a northern direction along Old Tamarack Road (Exhs. HO-1, Figure 5-2, HO-E-23). The pipeline would turn to the east on South Mountain Road, to the south on South Street, and then turn to the east to traverse the Pittsfield Country Club, cross under the Housatonic Railroad ROW and property of Miss Hall's School (Exhs. HO-1, Figure 5-2, HO-3, pp. 4-2, 4-3). The pipeline would then turn to the northeast along Holmes Road, cross the Housatonic River within an existing bridge utility bay, and turn to the east to enter Canoe Meadows (<u>id.</u>). The pipeline would travel along the eastern and northern perimeter of Canoe Meadows, exit Canoe Meadows and travel in an easterly direction along William Street to Elm Street (<u>id.</u>). The pipeline would then turn to the north, and travel parallel to the existing North Adams lateral, across private property and Brattlebrook Park to the point of connection with the Tenneco Interconnect (<u>id.</u>) The

Tenneco Interconnect and the Altresco spur line will link the proposed pipeline with the Altresco plant (Exh. HO-1, p. 4-1).

Berkshire's primary meter station site is located on the western edge of the Bousquet ski area, approximately 135 feet south of Tamarack Road ("primary meter station site") (Exh. BGC-2, Attach. B, pp. 3, 8). The primary meter station site is owned by Four Skiers Enterprises, Inc. ("Four Skiers"), the owners of the Bousquet ski area (id., p. 8). See Figure I.

The Company estimated the cost of installing the proposed pipeline and meter station along the primary route to be $7,290,000 (Exhs. HO-C-1, HO-C-2).

### 2. Alternative Facilities

The Company's alternative pipeline route is referred to by Berkshire as the revised Conrail/Cloverdale alternative (Exh. HO-1, p. 5-30).[68] The alternative route would begin at the primary meter station site[69] and travel along the path of the

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68/ The Conrail/Cloverdale Route was originally selected as an alternative route to the 11.2-mile Richmond Feedline route (Exh. HO-1, p. 5-30). Because Berkshire has withdrawn its proposal to construct the longer Richmond pipeline, Mr. Curtiss-Lusher acknowledged that for purposes of comparison, it would be more appropriate to compare the Bousquet route to a revised Conrail/Cloverdale alternative route commencing at the Bousquet meter station (Tr. 2, pp. 148-149). The Siting Council considers the revised Conrail/Cloverdale route to be the appropriate alternative pipeline route for comparison purposes in this proceeding.

69/ In addition to the primary meter station site, Berkshire evaluated five other meter station sites in the Bousquet/West Pittsfield area (Exh. BGC-2, p. 7, Attach. B, p. 1). These five meter station sites were not included in the Notice of Adjudication and therefore, may not be approved by the Siting Council. Nevertheless, since Berkshire presented an evaluation of the five meter station sites in its amended filing, the Siting Council reviews the manner in which Berkshire evaluated those sites to ensure that the Company did not overlook or eliminate any clearly superior alternative site. See Section III.C, below.

proposed primary route to Dan Fox Drive (Exh. HO-1, p. 5-30, Figure 5-4). The pipeline would then parallel Dan Fox Drive to South Street, and follow South Street in a northerly direction to the North Adams lateral ROW (id.). The route would then cross under the North Adams lateral and continue to parallel the North Adams lateral ROW through the Pittsfield Country Club, across Holmes Road, pass through other public and private properties, and under the Housatonic River (id.). The pipeline would continue to parallel the North Adams ROW, crossing Canoe Meadows, and crossing under East New Lenox Road, William Street, and Elm Street to the Tenneco Interconnect (id.). See Figure I. The Company estimated the cost of installing the pipeline and meter station along the revised Conrail/Cloverdale route to be $8,845,000 (Exhs. HO-C-1, HO-C-2).

3. Variations to the Proposed Facilities

In this proceeding, Berkshire also noticed segment variations for portions of the Bousquet Feedline route (Exh. HO-1, pp. 5-34 through 5-36, 5-36 n.27). The Company identified these segment variations as follows: (1) segment variation 3b would travel cross-country between South Mountain Road and the Pittsfield Country Club; (2) segment variation 4b would follow an existing golf cart path in a southeast direction across the Pittsfield Country Club, cross the North Adams lateral and the Housatonic Railroad tracks, then turn to the northeast, where it would cross the North Adams lateral again and continue across private property to Holmes Road; (3) segment variation 6a would cross the north central portion of Canoe Meadows, turn to the north on East New Lenox Road and continue along East New Lenox Road to William Street; (4) segment variation 6b would travel to the north on Holmes Street and turn to the east on William Street, thereby avoiding construction within Canoe Meadows; (5) segment variation 6d would travel to the north, east and south along the perimeter of Canoe Meadows, then turn to the east travelling across private property to New Lenox Road, and turn to the north and continue along East New Lenox Road to William Street; (6) segment variation 7b would turn to the west on Elm Street from William Street and then turn to the north and travel adjacent to the North Adams lateral; and (7) segment variation 8b would diverge from the North Adams ROW lateral prior to its crossing of Brattlebrook Park and travel to the east and north around Brattlebrook Park (id., pp. 5-34 through 5-36, 5-36 n.27, Figure 5-5).

## C. Site Selection Process

### 1. Overview of the Siting Process

Berkshire asserted that, consistent with the Siting Council's statutory mandate, it sought to select a pipeline route that would provide an appropriate level of reliability at the least cost and with minimal environmental impact (Exh. HO-1, p. 5-1). The Company worked with HMM[70] and a task force formed by the Mayor of Pittsfield ("Task Force") to select a new pipeline route (id., p. 5-2). Berkshire stated that the Task Force conducted its route selection process in conjunction with HMM (id., pp. 5-7 through 5-9).[71]

According to Berkshire, the first stage of the site selection process consisted of three levels of analysis: (1) a determination of regions of interest, i.e., general areas through which the pipeline could be constructed so as to deliver gas from

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70/ HMM is an engineering, environmental consulting, and planning firm (Exh. HO-1, p. 5-2).

71/ The Company's witness, Mr. Wall, stated that the site selection process was an interactive one between the Task Force and HMM (Tr. 3, p. 8). Mr. Wall stated that some of the site selection criteria were developed by HMM based on their experience, while others were developed based on the interests of the Task Force members (id.).

the Tennessee main line to the Altresco facility;[72] (2) a determination of areas to exclude or avoid within the regions of interest; and (3) an evaluation of route alternatives based upon the Siting Council's standards (id.).

Mr. Curtiss-Lusher[73] stated that the Task Force first looked at all the routes that had been reviewed in the 1990 Berkshire Decision (Phase II) including the route that was approved by the Siting Council in that Decision (Tr. 2, pp. 125, 133-135). Berkshire stated that the Task Force concluded that these route options were not desirable (Exh. HO-S-3). The Task Force then reexamined the possibility of Tennessee project alternatives, and examined new options which became available since the 1990 Berkshire Decision (Phase II) (id.). Based on this analysis, Berkshire stated that the Task Force, along with HMM, identified the Richmond Feedline route as the primary route, the Conrail/Cloverdale route as the alternative route, and numerous segment variations to the primary route (Tr. 2, pp. 126; Exh. HO-1, p. 5-10).[74]

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72/ Berkshire stated that, based on the natural characteristics of the area, two general corridors were found to be technically suitable for a pipeline route from the Tennessee main line to the Altresco facility in Pittsfield. (Exh. HO-1, p. 5-9). One such corridor, the "Lee/Lenox Corridor", passed through the towns of Lee, Lenox, and Pittsfield (id.). The Lee/Lenox Corridor was rejected for numerous reasons, including pipeline length, engineering problems, higher costs, and greater potential environmental impacts (id., p. 5-10). The other corridor, the Richmond/Pittsfield corridor, continued to be pursued (id., p. 5-9).

73/ Mr. Curtiss-Lusher was a member of the Task Force representing Altresco (Exh. AP-1, p. 11).

74/ Berkshire stated that segment variations to the primary route were developed because the Company identified a number of instances where potential engineering, environmental or regulatory concerns might make such variations necessary (Exh. HO-1, p. 5-19). These segment variations were also proposed by Berkshire in the event that easements could not be obtained for particular segments of the primary route (Tr. 4, Berkshire stated that in the second stage of the site selection process, HMM performed an analysis to validate the selection of the Richmond Feedline route based upon the Siting Council's criteria of reliability, least cost, and minimum environmental impact (Exh. HO-1, p. 5-11).[75] Berkshire stated that its analysis confirmed that the Richmond Feedline route was the superior route with respect to environmental impacts (id., sec. 5).

Subsequent to the selection of the Richmond Feedline route, Berkshire and Altresco discovered that the length of the proposed pipeline could be shortened due to the successful operation of the North Adams lateral and the interconnection facilities during the 1990-91 winter (Exh. AP-1, p. 17; Tr. 2, pp. 176-178). Reduced costs and further minimization of environmental impacts were cited by Berkshire as advantages of this approach (Exh. HO-1, p. 5-38). The Company stated that, for these reasons, it focussed on the selection of a shorter pipeline route commencing at the North Adams lateral, which resulted in the selection of the 6.2-mile Bousquet Feedline route (Exh. HO-2, p. 11).

After numerous meetings among Berkshire, Altresco, and Tennessee, in which analyses of available capacity were reviewed, Berkshire concluded that this shortened route, the Bousquet Feedline route, was the superior route in terms of providing a reliable energy supply with a minimum impact upon the environment

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pp. 229, 231, 248, 256, 258-259).

75/ In its route validation process, Berkshire used the route approved in the 1990 Berkshire Decision (Phase II) as a benchmark for evaluating other possible routes (Exhs. HO-1, p. 5-18, BGC-2, Attach. A, pp. A-33, A-34)). However, Mr. Curtiss-Lusher stated that this route was not considered to be an alternative in this proceeding (Tr. 2, pp. 149-150).

at the least cost (id., p. 3).[76] The Bousquet Feedline route was then presented to the Task Force, which adopted the route as its primary route (Tr. 2, pp. 175-176). With the exception of one segment variation,[77] the Bousquet Feedline route is essentially the Task Force's Richmond Feedline route shortened by 4.5 miles (id., p. 176; Exh. HO-S-10). HMM performed a validation analysis for the Bousquet route similar to the one performed for the Richmond Feedline route (Exh. BGC-2, Attach. A, pp. A-25, A-26, A-33 through A-35).

2. Development of Siting Criteria

a. Description

Berkshire stated that the Task Force adopted the site selection criteria used by Berkshire in its selection of the route approved in the 1990 Berkshire Decision (Phase II) (Exh. HO-S-3). The criteria used by Berkshire in that proceeding were environmental impacts, cost, construction constraints, and reliability. 1990 Berkshire Decision (Phase II), 20 DOMSC at 161. In addition, Berkshire stated that the Task Force adopted a statement of principles which set forth its concerns in selecting a pipeline route (Exhs. HO-S-3, Attach., AP-1, Attach. A, p. 2). Those principles included concerns such as proximity of the pipeline to residences, pipeline safety, environmental impacts,

76/ Mr. Curtiss-Lusher stated that in the process of developing a shorter primary route, there were numerous discussions and evaluations as to how far along the system Tennessee could guarantee adequate deliveries to the Altresco facility (Exh. AP-1, p. 17). Mr. Curtiss-Lusher asserted that Tennessee's calculations indicated that adequate volumes and pressures could be delivered if the pipeline commenced at a point 4.5 miles from the Tennessee main line, which is the Bousquet ski area (id.).

77/ Segment variation 6c originally was a variation to the Richmond Feedline route (Tr. 2, p. 132). The Company stated that due to concerns of the Audubon Society, it decided to include this segment variation in the Bousquet Feedline route. (Tr. 4, pp. 250-251).

costs, and minimizing time to obtain necessary permits (id.).

Berkshire indicated that the Task Force did not apply numerical scores or weights to the criteria it considered, but evaluated them in a more subjective fashion (Tr. 3, p. 4; Exh. HO-S-18). Mr. Curtiss-Lusher and Mr. Wall stated that the Task Force was most concerned about sensitive receptors (including proximity to residences and wells), wetlands, and open space and recreation (Exh. HO-S-20(d); Tr. 3, pp. 4, 10, 14).

Berkshire stated that HMM selected and defined a set of human and natural environmental criteria, based upon federal, state, and local environmental standards,[78] the professional judgment of Berkshire and its consultants, the Task Force, and the concerns expressed by officials and residents of Richmond and Pittsfield for use in its validation process (Exh. BGC-2, Attach. A, p. A-1). Further, Berkshire stated that HMM did apply numerical weights and quantified scores for the environmental criteria it utilized in its validation analysis (id., Attach. A).

Berkshire stated that the human environmental criteria applied in HMM's validation process were selected to account for concerns associated with construction of a pipeline in proximity to populated areas (id., p. A-3). These criteria were identified as: sensitive receptors,[79] archaeological and historic

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78/ Berkshire stated that the environmental criteria were, in part, developed from pertinent criteria evaluated under the Massachusetts Environmental Policy Act ("MEPA"), by the Siting Council, and by other agencies involved in pipeline permitting (Exh. HO-S-20).

79/ Sensitive receptors include homes, churches, schools, and hospitals within close proximity of the pipeline route (Exh. BGC-2, Attach. A, p. A-3). The Company considered the proximity of the pipeline to sensitive receptors in its review, and attempted to maintain at least a minimum distance of 20 feet and, where possible, 50 feet, between the pipeline and residences (Tr. 3, p. 67, Tr. 5, pp. 40-41; Exh. HO-RR-35).

resources, open space and recreation, scenic roads,[80] roadway alignment[81] and community concern and acceptance[82] (id., pp. A-3 and A-4). Mr. Wall testified that the use of pipeline safety as a separate criterion was not possible because it could not be defined in a meaningful way for purposes of the validation analysis (Tr. 3, pp. 66-67). However, Mr. Wall also stated that proximity of the pipeline to sensitive receptors was an element of ensuring long-term safety (id.).

Berkshire stated that natural environmental criteria developed and used by HMM in its validation process were selected to account for those significant natural resources that would be impacted by construction and/or operation of the pipeline (Exh. BGC-2, Attach. A, p. A-4). The natural criteria reviewed by Berkshire were identified as: wetlands,[83] water resources,[84] forest resources, wildlife habitat, and active agriculture (id., pp. A-4 through A-6).

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80/ Berkshire stated that scenic roads were originally chosen as a criterion due to concerns expressed regarding construction along roadways in Richmond (Exh. BGC-2, Attach. A, p. A-4). Berkshire added, however, that scenic roads are not an issue for the Bousquet Feedline route (id., p. A-25; Exh. HO-S-20, Tables S-20-3, S-20-4, S-20-8).

81/ Berkshire stated that roadway alignment was chosen as a criterion due to concerns related to potential traffic disruption during construction of the pipeline within roadways (Exh. BGC-2, Attach. A, p. A-4).

82/ Berkshire stated that this criterion was included to address the Siting Council's suggestion in the 1990 Berkshire Decision (Phase II) to include community input as part of the site selection process (20 DOMSC at 163), and to reflect the input of the Task Force (Exh. BGC-2, Attach. A, p. A-4).

83/ Berkshire stated that this criterion included two subcategories -- wooded wetlands and open or shrub swamp (Exh. BGC-2, Attach. A, p. A-5).

84/ Berkshire stated that this criterion included two subcategories -- fishable streams and private water supplies (Exh. BGC-2, Attach. A, p. A-5).

As part of the validation analysis performed by HMM for Berkshire, subjective weights were developed for each of the human and natural environmental criteria (id., p. 5, Attach. A, p. A-1).[85] Berkshire stated that raw impact data was developed for each of the criteria for each route alternative based on field evaluations, literature searches, aerial photography, and review of topographic maps and other environmental data (id.). The impact data was then compared for the alternative routes and scaled to account for unit dissimilarity, i.e., the linear feet of roadways versus the number of sensitive receptors (id.). Berkshire stated that weights were applied to quantitatively evaluate the impacts for all of the natural and human environmental criteria (id.).[86] Berkshire noted that this methodology did not include a quantitative analysis of the criteria of cost or reliability (id., p. A-2).

With respect to the meter station site, Berkshire stated that the criteria used by HMM to identify and select a meter station site included: (1) reasonable distance to the North Adams lateral; (2) reasonable distance to the proposed Bousquet

85/ Berkshire stated that these weights were based on three factors: (1) short-term construction impacts; (2) long-term construction impacts; and (3) ability to mitigate impacts associated with construction and operation of the facility (Exh. BGC-2, Attach. A, p. A-1). Numerical weights were assigned to each criterion based on the severity of the impact, i.e., a high impact was assigned a value of three, a medium impact was assigned a value of two, while a low impact was given a value of one (id., pp. A-16, A-17). The highest possible weight under this methodology would be 9.0, while the lowest weight would be 3.0 (id.).

86/ The raw data were scaled on the basis of 100 percent to account for the dissimilarity of units of measurement among the criteria (Exh. BGC-2, Attach. A, p. A-23). The route alternative with the greatest amount of impacted resource received a 100 percent designation, while the compared alternative received a proportional fraction of 100 percent based on its impact (id.). These percentages were then multiplied by the weights assigned to the particular criterion to obtain a score for each criterion for each route (id.).

Feedline route; (3) a location along the North Adams lateral that would ensure reliable delivery of necessary gas supplies; (4) site availability; and (5) environmental concerns (Exh. HO-MC-1A). Berkshire stated that HMM utilized the same environmental criteria used for selecting the pipeline route in the meter station site selection process (Exh. BGC-2, Attach. B, pp. 2, 4-7). In addition, Mr. Curtiss-Lusher testified that there were discussions with the residents in the vicinity of the Bousquet ski area concerning the siting of the meter station (Tr. 3, p. 172-174). The record does not indicate that any weighting, ranking or quantitative analysis of the criteria was performed with respect to the meter station sites (Exh. BGC-2, Tables 1 and 2).

b. Arguments of the Parties

Berkshire and Altresco noted that in the 1990 Berkshire Decision (Phase II), the Siting Council found that the Company had developed a reasonable set of siting criteria (Berkshire/Altresco Initial Brief, p. 60). Berkshire and Altresco argued that the site selection process in this proceeding improves upon the process utilized in the 1990 Berkshire Decision (Phase II), because of the involvement of the Task Force and the use of HMM's environmental validation methodology (id.).

Motyl/Clerici argue that they and other residents in the vicinity of the proposed Bousquet meter station site had little or no opportunity to provide input to the Task Force with respect to the site selection process (Motyl/Clerici Initial Brief, pp. 7, 10, 13, 14-16, 18).

c. Analysis

The Siting Council notes that in previous reviews of gas pipelines it has accepted criteria such as those developed by Berkshire for use in the identification and evaluation of pipeline routes. The Siting Council has found previously that a range of criteria such as cost, environmental impacts, and reliability generally are appropriate for siting natural gas pipelines. 1991 Berkshire Decision, 23 DOMSC at 329; 1990 Bay State Decision, 21 DOMSC at 54; 1990 Berkshire Decision (Phase II), 20 DOMSC at 162. At the same time, however, the Siting Council has stated that these criteria are very broad, and therefore do not provide insight into how potentially conflicting concerns within these criteria are addressed. Id. In this case, Berkshire has developed very specific natural and human environmental criteria for the proposed pipeline and for the meter station site as well.

In addition, Berkshire has incorporated community input into its site selection process in this case through the Task Force and has included community concern as one of its siting criteria. In response to public input, Berkshire identified a primary route, an alternative route and segment variations that were more acceptable to the community than the route previously approved in the 1990 Berkshire Decision, Phase II. Clearly, Berkshire has significantly improved its consideration of community input through its involvement with the Task Force.

With respect to the selection of the meter station site, however, the record indicates that consideration of community input was not as extensive as the consideration given community input in selecting the pipeline route. The Siting Council notes that there was no representation on the Task Force from the area in the vicinity of the proposed Bousquet meter station site. In the future, we encourage companies to consider input from all affected communities on all aspects of a proposal.

The Siting Council also notes that the Company did not develop any specific cost or reliability criteria. Further, cost was not a criterion considered in the selection of the meter station site, nor was any cost analysis performed for the various meter station sites reviewed by Berkshire. The Siting Council encourages project proponents to develop specific cost and reliability criteria, to the extent possible.

With respect to weighting site selection criteria, in previous decisions, the Siting Council has expressed concerns regarding the absence of weights for site selection criteria. Enron, 23 DOMSC at 127; EEC, 22 DOMSC at 321; West Lynn, 22 DOMSC at 78-79; MASSPOWER, 20 DOMSC at 378-379; 1990 Berkshire Gas Decision (Phase II), 20 DOMSC at 161-162. The Siting Council has stated that the development of numerical values and weights and the ranking of alternatives based on such numerical values and weights is a necessary step in any process for identifying and evaluating routes or sites. 1991 Berkshire Decision, 23 DOMSC at 329. In the 1990 Berkshire Decision (Phase II), the Siting Council was concerned that the Company did not establish weights for its identified criteria in order to balance potentially competing concerns among the criteria, such as weighing cost and environmental impacts (20 DOMSC at 162).

In this case, Berkshire developed weights for each environmental criterion to provide a score for each route. However, weights were not developed for the cost and reliability criteria. Consequently, while the Company's methodology allows for quantitative comparisons among competing environmental criteria, it does not provide for a quantitative comparison among environmental criteria and the other siting criteria of cost and reliability.[87] Berkshire also failed to perform any weighting,

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87/ The Siting Council also notes that the analysis performed by HMM to validate the Richmond Feedline route was performed after the route was chosen by the Task Force. While the Task Force did consider the criteria spelled out in its statement of principles and those criteria utilized in the 1990 Berkshire Decision (Phase II), the Task Force did not apply an objective, quantitative analysis to the possible routes. Although the Siting Council encourages companies to incorporate community input into their siting decisions, (1990 Berkshire Decision (Phase II), 20 DOMSC at 163), the ultimate responsibility for demonstrating that clearly superior options have not been overlooked or eliminated continues to rest squarely ranking or quantification of criteria used to select the meter station site. Thus, Berkshire has only partially addressed the Siting Council's concerns regarding the absence of weights for site selection criteria.

With respect to the weights developed for the environmental criteria, generally those weights were developed appropriately by the Company. The Company developed a weighting approach incorporating the likely severity of project impacts for respective criteria. Specifically, weights were assigned based both on observation of the quality of potentially affected resources in the field and on general characterizations of the manner in which proposed facility construction is likely to affect such resources in the short term, in the long term, and with consideration of mitigation potential. The assigned weights were then applied to raw data values reflecting the quantity of affected resources identified in the field. This weighting approach thus goes well beyond those presented by applicants in previous Siting Council reviews and, by-and-large, represents an improvement over the weighting approaches used in those previous proceedings.

However, the Siting Council notes some concerns with the Company's weighting approach for environmental criteria. In developing subcategories for some of its criteria, the Company may have increased the relative overall weight for such criteria in unintended ways. For example, the Company developed three subcategories for its roadway alignment criteria -- primary, secondary and local roadways -- and assigned weights of 5.0 to each subcategory, summing to a total of 15.0 for the criteria as a whole (Exh. BGC-2). In the case of the sensitive receptor

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with the applicant. 1990 Bay State Decision, 21 DOMSC at 58. The Siting Council is concerned that, in this case, the objective weighting of criteria and ranking of pipeline routes took place after the route was already selected, rather than as part of the process leading to the selection of that route.

criteria, however, no subcategories were established and an overall weight of 6.0 was assigned (id.). The Siting Council notes that, as a possibly incidental result of the subcategorization of criteria, the overall roadway alignment weight is more than twice the sensitive receptor weight.

Although the Siting Council has some concerns with the Company's weighting approach for environmental criteria, a strength of the Company's process is the incorporation of an approach for standardizing raw data scores prior to applying weights to the raw data. This is an additional difference from approaches considered in previous Siting Council reviews. Under this approach, a raw data value of 100 percent, or 1.0, is assigned to the alternative with the greatest quantity of affected resources for each criterion, and the other alternatives are assigned scaled values between zero and 1.0 for that criterion. The Siting Council notes that this approach facilitates aggregation of the weighted scores in standardized terms. However, the approach also limits the ability to reflect the relative importance of impacts between criteria, based on the relative significance of the quantity of affected resources under each criterion. Although the Company intended that its use of weights accommodate any necessary balancing among criteria, it is unclear whether the Company's overall approach in fact incorporates an ability to accurately reflect differences between criteria in the quantity of affected resources -- particularly in instances where an alternative shows an unusually large raw data value.[88] Rather, as described above and reflected in the

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88/ As an example, the number of sensitive receptors affected by the route approved in the 1990 Berkshire Decision (Phase II), revised from 11.5 miles to 6 miles, is 219 -- more than three times that of the Bousquet Feedline route (Exh. HO-S-20). Based on the Company's standardization approach, the corresponding sensitive receptor scores for the revised previously approved route and the Bousquet Feedline route are 6.0 and 1.92, respectively -- representing fractions of the overall scores of 44.4 and 52.3 for the two routes, respectively (id.).

Company's analysis, the weights reflect a largely generic assessment of the nature and severity, but not the quantity, of impacts for each criterion.

Finally, with respect to the manner in which weights were applied to specific criteria, the Siting Council notes that the criteria of wooded wetlands and forest resources should have been given greater weight, since trees will be removed from these areas and will not be replaced within the permanent ROW, and only about half of the cleared area will be allowed to return to its natural state. Otherwise, under the weighting system established by Berkshire, impacts to forest resources and wooded wetlands were undervalued when the route comparisons were made.

Nevertheless, the Siting Council finds that, on balance, Berkshire has developed a reasonable set of criteria for identifying and evaluating alternative routes and sites.

3. Application of Siting Criteria

a. Description

Berkshire used its site selection criteria to identify the Bousquet Feedline route, the revised Conrail/Cloverdale alternative route, and numerous segment variations to the primary route. As part of the validation analysis described above, Berkshire stated that HMM performed a comparative analysis of environmental impacts associated with the Bousquet Feedline

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Further, if it were hypothetically assumed that the number of affected receptors along the revised previously approved route were double the actual count, that is 438 receptors, the net effect on the Company's comparison of the two routes would be minimal -- a change of only 0.96 in the relative scores of the two routes. In fact, for infinitely large increases in the number of receptors along the revised previously approved route, the maximum change in the relative scores would be 1.92. Thus, in situations where the raw data score of a particular route under a particular criterion is unusually large, the Company's standardization approach imposes limitations on the ability of the Company's overall methodology to proportionately reflect the actual magnitude of impact.

route, the revised Conrail/Cloverdale alternative route, the route approved in the 1990 Berkshire Decision (Phase II), the Richmond Feedline route, and segment variations to the Richmond and Bousquet Feedline routes (Exhs. BGC-2, Attach. A, HO-S-20).

When compared to the revised Conrail/Cloverdale alternative route, the Bousquet Feedline route compared favorably to the alternative route with respect to environmental criteria (Exh. HO-S-20, Table S-20-3).[89] Further, the Company performed a comparison of the Bousquet Feedline route to both the Richmond Feedline route and the full-length 11.5-mile route approved in the 1990 Berkshire Decision (Phase II) (Exh. BGC-2, Attach. A, p. A-34). That comparison resulted in a conclusion that the shorter 6.2-mile Bousquet Feedline route would have less environmental impact (id.).[90] Finally, based on application of

89/ The Bousquet Feedline route had an overall score of 50.2, and the revised Conrail/Cloverdale alternative route received a score of 62.4 (Exh. HO-S-20, Table S-20-3). A lower score implies less environmental impact (Exh. BGC-2, Attach. A, p. A-23).

90/ The Siting Council notes that while Berkshire has not presented the route approved in the 1990 Berkshire Decision (Phase II) as a noticed alternative here, the Company did compare both the full 11.5-mile and a revised 6-mile version of that route to the Bousquet route. Based on a quantitative analysis of environmental criteria alone, the revised 6-mile version of the previously approved route appears to be superior to the Bousquet Feedline route. However, Berkshire noted that legislative approval required under Article 97 of the Massachusetts Constitution could not be obtained for a portion of this route, thereby rendering the route impractical. (Exh. HO-S-20; Tr. 2, p. 171-173).

Berkshire also noted that substantial community opposition to portions of that route through more densely populated areas render it undesirable from both a cost and a reliability perspective, primarily due to delays in permitting and construction (Tr. 3, pp. 33-34). The Siting Council has previously recognized the appropriateness of siting high pressure natural gas transmission pipelines in a manner which avoids densely populated areas and minimizes exposure to possible pipeline accidents. 1990 Bay State Gas Decision, 21 DOMSC at 54-55; 1990 Berkshire Decision (Phase II), 20 DOMSC at 199.

its siting criteria, Berkshire stated that none of the segment variations were found to be environmentally superior to the Bousquet Feedline route (Exh. HO-RR-25).

With respect to meter station sites, Mr. Curtiss-Lusher testified that Berkshire attempted to place the meter station as close to the Altresco facility as possible, thereby reducing the length of the pipeline and its associated costs as much as possible (Tr. 2, pp. 180-181). Based on calculations performed by Tennessee, Berkshire determined that the vicinity of milepost 4.5, the Bousquet ski area, was the farthest point along the North Adams lateral whereby sufficient volumes and pressures of gas could be sustained to both the Altresco facility and to the North Adams meter station (id., pp. 181-182). Once the Bousquet ski area was selected, Berkshire tried to identify sites in that area large enough to build a meter station (id. p. 181).[91]

Berkshire stated that six areas were identified as possible meter station sites based upon the criteria developed by the Company (see Section III.C.2, above), information provided by Tennessee, and HMM's familiarity with the project and the area (Exh. HO-MC-1A). The six sites identified were: (1) the primary meter station site;[92] (2) Bousquet East site; (3) Dan Fox Drive site; (4) Old Tamarack Road site; (5) Bousquet North site; and

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91/ A site study area extending from Knox Road to a point 500 feet east of Old Tamarack Road and south from the Tennessee North Adams Lateral north to the upper portion of Old Tamarack Road was evaluated by HMM at the request of Berkshire and Altresco, utilizing the criteria developed by the Company (see Section III.C.2, above) (Exh. HO-MC-1A).

92/ The Company stated that the primary meter station site was selected in a decision making group that included the landowner, Tennessee, Berkshire, and Altresco (Tr. 4, p. 117). The site was then presented to the Task Force as part of the approval process for the Bousquet Feedline route, and then ratified by the Task Force (id., pp. 117, 120).

(6) West Pittsfield meter station site (Exh. BGC-2, Attach. B, p. 1).[93]

Berkshire stated that HMM prepared an environmental assessment of the various sites for the meter station based upon raw data,[94] and the same human and natural environmental criteria used in evaluating the various pipeline routes (Exh. BGC-2, Attach. B, pp. 1-2, 4-7, Tables 1 and 2). Mr. Wall stated that, based upon the environmental criteria examined, the primary site is comparable to the Bousquet East, Dan Fox Drive, and Old Tamarack Road sites and superior to the Bousquet North and West Pittsfield meter station sites (id., p. 8).[95,96]

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93/ The Dan Fox Drive, Old Tamarack Road, and Bousquet North sites were recommended to Berkshire by the landowner (Tr. 3, p. 144). According to Mr. Curtiss-Lusher, although the owner of the Bousquet ski area property initially suggested the Old Tamarack Road site, the owner was later unwilling to allow a sufficiently-sized parcel of land to be used for the construction and operation of a meter station at that location (id., p. 167).

94/ The raw data was based on field evaluations, literature searches, aerial photography, topographic maps and other environmental materials (Exh. BGC-2, Attach. B).

95/ Berkshire stated that construction at the Bousquet North site would require filling 0.6 acres of vegetated wetland, thereby altering 0.6 acres of wildlife habitat designated by the Massachusetts Division of Fisheries and Wildlife, Natural Heritage and Endangered Species Program (Exh. BGC-2, Attach. B, pp. 10-11). Berkshire stated that such a wetland alteration is not permittable in Massachusetts (id., Attach. B, p.11).

Berkshire stated that the West Pittsfield meter station site would require the greatest amount of new pipeline construction, thereby having the most environmental impact (id., Attach. B, p. 11, Tables 1 and 2). In addition, the Company determined that it was not possible to use the already existing meter station for a number of reasons, including inadequate size and regulatory concerns (id.; Tr. 3, p. 166). Berkshire also determined that the physical location of that particular site would make it very difficult to construct a second meter station there, and would necessitate additional pipeline construction in wetlands (Tr. 2, pp. 179-180).

Berkshire stated that the location of the meter station at the Bousquet East, Dan Fox Drive, and Old Tamarack Road sites would not provide adequate volumes and pressures to the Altresco facility and Berkshire's customers (Exhs. BGC-2, pp. 8-9, HO-RR-12). Berkshire indicated that locating the meter station at any of those three sites would result in lowering the pressure at the North Adams meter station to unacceptable levels (Exh. HO-RR-12). Thus, based upon the criterion of reliability, Berkshire stated that these sites were eliminated from further consideration (Exh. BGC-2, pp. 8-9).[97]

With respect to the criterion of site availability, Berkshire stated that the owner of the ski area would not make the Bousquet East and Old Tamarack Road sites available to Berkshire because a meter station would interfere with the ski area's commercial activities on those sites (id., p. 9). Berkshire stated that, therefore, these sites did not meet the Company's criterion of site availability.[98, 99]

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96/ As noted in Section III.C.2.a, above, although Berkshire compared the raw data for these sites, no weighting, ranking or quantitative analysis of the criteria was performed with respect to the meter station sites (Exh. BGC-2, Attach. B, Tables 1 and 2).

97/ Mr. Wall also testified that Berkshire considered Tennessee's concerns regarding the length of the interconnect required at the Old Tamarack Road site (Exh. BGC-2, p. 9). The interconnect at that site would have to be approximately 850 linear feet (id., Attach. B, p. 10). According to Berkshire, Tennessee was concerned that its FERC authorization might not cover an interconnect of that length and that they would have to refile for FERC approval (id., p. 9; Exh. HO-E-52; Tr. 3., pp. 122-126).

98/ Berkshire also asserted that the Dan Fox Drive and Old Tamarack Road sites could be affected by proposed roadway improvements to Dan Fox Drive, including the construction of a roadway interchange (Exh. BGC-2, Attach. B, pp. 9-10). Berkshire stated, however, that the roadway proposal appears to be dormant at this time, having been defeated in municipal elections (Tr. 3, pp. 154-155, Tr. 4, p. 204).

b. Arguments of the Parties

The Town of Richmond, Biss and Brandon support the Bousquet Feedline route as the superior route (Richmond Initial Brief, p. 15; Biss/Brandon Reply Brief, p. 1). Motyl/Clerici present numerous arguments with respect to the selection of the meter station site. First, Motyl/Clerici contend that the record is inadequate to support Berkshire and Altresco's assertion that gas pressures and volumes would be inadequate to serve both Altresco and the North Adams meter station if the meter station is located beyond the primary site further along the lateral toward the Altresco facility (Motyl/Clerici Initial Brief, pp. 6, 51). Motyl/Clerici assert that Berkshire failed to provide calculations to substantiate modeling results demonstrating that pressures at North Adams would be inadequate if the meter station is located at either the Bousquet East, Dan Fox Drive, or Old Tamarack Road sites (id., pp. 6, 30, 51). Motyl/Clerici also argue that the siting of the meter station should not be based upon "contractual requirements", which could be amended subject to FERC approval (id., pp. 6, 21).

Motyl/Clerici further contend that Berkshire did not provide at least two viable alternative meter station sites, and failed to provide a reasonable range of practical site alternatives by selecting sites that did not meet the Company's own siting criteria or had major flaws (id., pp. 28, 33, 43, 44, 49). Finally, Motyl/Clerici assert that the Old Tamarack Road site is the superior site for numerous reasons, including site

99/ Mr. Wall testified that Berkshire considered Tennessee's concerns regarding site security at the Bousquet East, Dan Fox Drive, and Bousquet North sites (Exh. BGC-2, p. 9). However, site security was not listed as one of the site selection criteria for the meter station site (id., Attach. B).

size, and impacts on forests or wildlife (id., pp. 27, 29, 60).[100]

c. Analysis

In this section, the Siting Council examines whether Berkshire applied its siting criteria to its siting options in a consistent and appropriate manner which ensured that no clearly superior routes or sites were overlooked or eliminated.

The Siting Council notes that Berkshire, along with the Task Force, conducted a thorough search to identify feasible routes for the proposed pipeline. The Company's Bousquet Feedline route, the revised Conrail/Cloverdale alternative route, and the segment alternatives were subjected to a set of weighted criteria encompassing natural and human environmental impacts, and then compared to each other utilizing scores derived from the methodology described in Section III.C.2.a, above.

Accordingly, with respect to the pipeline, the Siting Council finds that Berkshire has applied its site selection criteria consistently and appropriately and in a manner which ensures that it has not overlooked or eliminated any siting options which are clearly superior to its proposal.

With respect to the meter station sites, the Bousquet East, Dan Fox Drive, and Old Tamarack Road sites fail to meet the Company's criterion that the site should ensure reliable delivery of necessary gas supplies. In addition, the Bousquet East and the Old Tamarack Road sites fail to meet Berkshire's criterion of site availability, since, according to Berkshire, the owner of those sites is unwilling to make them available for construction of a meter station.

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100/ With respect to Tennessee's concern about the length of the interconnect at the Old Tamarack Road site, Motyl/Clerici point out that there is nothing in the record establishing that FERC regulations prohibit interconnects exceeding a specified length (Motyl/Clerici Initial Brief, pp. 30, 50).

However, Berkshire did evaluate three other sites that meet the criteria -- the primary site, the Bousquet North site, and the West Pittsfield meter station site. These sites are all within a reasonable distance of the North Adams lateral and the Bousquet Feedline route, meet the criteria of reliability and site availability, and were analyzed for environmental impacts.

Motyl/Clerici argue that the record is insufficient to support the Company's assertions that gas pressures and volumes would be inadequate to serve the Altresco facility and North Adams if the meter station is located beyond the primary site. We note, however, that the record demonstrates that pressures at the North Adams meter station would be reduced to unacceptable levels, assuming firm deliveries are made to the Altresco facility and Berkshire fully utilizes its pipeline delivery entitlements, if the proposed meter station were located beyond the primary site.[101,102]

Finally, turning to Motyl/Clerici's argument that the Old Tamarack Road site is the superior site, the Siting Council notes that the Old Tamarack Road site does not meet the threshold criteria of reliable delivery of gas supplies and site availability and, therefore, is not a clearly superior site.

Based on the foregoing, the Siting Council finds that Berkshire has appropriately applied a reasonable set of criteria for identifying and evaluating alternative routes and sites in a manner that ensures that it has not overlooked or eliminated any

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101/ While contractual volumes, taken alone, do not establish need for proposed facilities, they do warrant consideration in a company's determination of where to site facilities.

102/ Motyl/Clerici's arguments regarding contractual requirements and the West Pittsfield meter station's impact on pressure at the North Adams meter station are addressed in Section II.A.3.c, above.

clearly superior routes and sites.[103]

4. Geographic Diversity

In this section the Siting Council considers the second prong of our practicality test -- whether the Company's site selection process included consideration of site alternatives with some measure of geographic diversity.

The Company alleged that in order to meet the Siting Council's geographic diversity requirement, it considered two routes for the proposed gas pipeline, the Bousquet Feedline route and the revised Conrail/Cloverdale alternative route (Berkshire/Altresco Initial Brief, pp. 58-59). The Company also asserted that due to the location of the existing Altresco and Tennessee facilities, the area of consideration for pipeline alternatives is necessarily limited (id.). Further, the Company indicated that the Bousquet Feedline travels approximately 14,000 feet within roadways while the revised Conrail/Cloverdale route travels approximately 3,400 feet within roadways (Exh. HO-S-20, Table S-20-3).

In the present case, the primary and the alternative routes overlap for approximately one mile (Exh. HO-E-9, Table E-9-1). Although there is some overlap, the Siting Council notes that this overlap is not significant and occurs at the beginning of the pipeline route, near the primary meter station site, and at the end, as the routes approach the Altresco facility. Since both routes have a common starting point and have to interconnect at the Altresco facility, it is not

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103/ The Siting Council notes that had we found one of the alternative meter station sites to be a clearly superior site, the Siting Council could not have approved that site since none of the alternative meter station sites were included in the Notice of Adjudication and Public Hearing. Therefore, the Siting Council encourages all companies to carefully consider this possible outcome in deciding whether to notice alternative sites for ancillary facilities.

unreasonable to assume that there may be some limitations regarding the location of the routes at the beginning and ending points. Further the Siting Council notes that the Company chose two different routes that traverse different terrain. The revised Conrail/Cloverdale alternative route, for the most part, travels cross-country along an existing pipeline ROW while the Bousquet Feedline route follows roadways for approximately half its distance. Therefore, the record demonstrates that the primary and the alternative routes are geographically diverse.

With respect to the meter station, Motyl/Clerici argue that the additional meter station sites evaluated by the Company are just variations of the primary meter station site, and therefore, do not meet the Siting Council's standard of geographic diversity (Motyl/Clerici Initial Brief, p. 44).

The Siting Council notes that five of the six meter station sites evaluated by the Company, including the primary site, are in the vicinity of the Bousquet ski area (Exh. BGC-2, pp. 3, 9). The location of the other meter station site is at the West Pittsfield meter station which is approximately 3,500 feet from the Bousquet delivery point (Exh. BGC-2). Therefore, the record demonstrates, that in this case, the primary meter station site and the West Pittsfield meter station site are geographically diverse.

Based on the foregoing, the Siting Council finds that Berkshire has identified at least two practical routes and sites with some measure of geographic diversity.

5. Conclusion on the Site Selection Process

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

Accordingly, the Siting Council finds that Berkshire has considered a reasonable range of practical siting alternatives.

### D. Cost Analysis of the Proposed and Alternative Facilities

The Company asserted that construction of the proposed pipeline along the primary route is the least cost alternative (Exh. HO-C-1). Berkshire estimated that construction of the proposed pipeline along the primary route would cost $7,290,000 while construction along the alternative route would cost $8,845,000 and provided a breakdown of expenses as follows:

| Category | Primary Route | Alternative Route |
|---|---|---|
| Engineering, design & planning | $1,580,000 | $1,655,000 |
| Construction & materials | 3,275,000 | 4,050,000 |
| Licenses, permits & approvals | 465,000 | 535,000 |
| Easements | 490,000 | 750,000 |
| Miscellaneous & contingency | 575,000 | 950,000 |
| Meter station | 905,000 | 905,000 |

(Exhs. HO-C-1, HO-C-2)

The Company indicated that it did not anticipate actual costs would vary more than five percent from estimated costs because cost estimates were based on firm price quotations, unit price quotations, material already purchased and experience with similar projects (Exh. HO-C-1; Tr. 1, p. 187).

The Company explained that the greater design and construction costs of the alternative route result primarily from the Housatonic River crossing and a number of road crossings that would require boring as well as blasting and ledge removal (Exh. HO-C-6). Additionally, the Company explained that easement costs would be higher for the alternative route because a greater number of private landowners would be affected by the alternative route than by the primary route (id.). The Company further explained that the miscellaneous and contingency costs of the alternative route are potentially greater than corresponding costs of the primary route due to anticipated community opposition to portions of the alternative route (id.).[104]

In addition, Berkshire provided estimates of the cost differences between construction of each segment variation and the corresponding segment of the primary route (id.). In each instance, Berkshire noted that construction along the segment variation would be more costly than construction along the corresponding segment of the primary route (id.).[105]

Based on the foregoing, the Siting Council finds that the Company's primary route is preferable to the alternative route and to the primary route with any of the segment variations with respect to cost.

## E. Environmental Analysis of the Proposed and Alternative Facilities

### 1. Environmental Impacts of the Primary Route

#### a. Land and Water Resources

##### i. Trees

The Company indicated that construction of the proposed facilities along the primary route would require clearing of approximately seven acres of forest, including 4.85 acres in the vicinity of Brattlebrook Park, 1.3 acres within the Pittsfield

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104/ Mr. Curtis-Lusher indicated that anticipated community opposition to segments of the alternative route includes the opposition of the Audubon Society to the Canoe Meadows crossing (Tr. 4, p. 239).

105/ The Company indicated that the increased cost of construction of route segment variations would range from $35,400 to $91,100 more than the cost of construction of corresponding segments of the primary route due primarily to increased permitting, right-of-way and construction costs (Exh. HO-C-1).

Country Club for construction of the pipeline, and an additional 0.8 acre within the Bousquet Ski Area for construction of the meter station (Exhs. HO-1, Figure 5-5, BGC-2, Attach. A, pp. A-25, A-26, Attach. B, p. 8).[106,107] In addition, the Company stated that a small number of mature trees, approximately 17, would be cleared in order to construct within Canoe Meadows (Exh. HO-E-29; Tr. 5, p. 43). However, the Company asserted that impacts to trees both within the ROW and adjacent to the ROW have been minimized by (1) limiting the number of trees that will be removed by pipeline construction, and (2) avoiding potential construction impacts to remaining trees (Tr. 5, pp. 44-46).

With regard to tree clearing, the Company maintained that tree clearing within the vicinity of the Pittsfield Country Club would be limited by (1) minimizing the size of the construction ROW, and (2) adjusting the pipeline alignment in one area to avoid a number of significantly large trees (id.). The Company explained that the 50-foot wide construction ROW that would be utilized within this area is substantially less than a typical construction ROW of 80 to 100 feet for a 12-inch diameter pipeline (id.). The Company indicated that it would not be feasible to further reduce the width of the construction ROW because the cleared area must be wide enough to allow adequate swing room for operation of construction equipment, and adequate clearance from the trench edge for equipment (Exh. HO-E-37). In addition, the Company stated that, if soils are found to be unstable, the trench width would need to be increased and a

106/ Tree clearing for the meter station construction includes construction of both the Tennessee and Berkshire portions of the meter station as well as the interconnecting pipeline to the North Adams lateral (Exh. BGC-2, Attach. B, p. 8).

107/ Of the seven acres, 4.85 acres in the vicinity of Brattlebrook Park is wooded wetland and the remainder is upland forest (Exh. BGC-5, Attach. 4). Impacts to wooded wetlands are discussed in Section E.1.a.iii, below.

larger area for spoils would be necessary (id.).[108] The Company noted that only a ten-foot wide permanent ROW would be maintained within the Pittsfield Country Club (Exh. HO-E-54).[109] However, the Company noted that it would not replant trees within the temporary ROW and that it would take from 20 to 30 years for the forested area to be restored by natural regrowth (Tr. 5, p. 50).[110]

In addition, the Company noted that tree removal within Canoe Meadows could be avoided by construction along a route segment variation, labeled segment variation 6b by the Company, which would follow Holmes Road and William Street instead of crossing the sanctuary (Exh. HO-C-6). However, the Company indicated that this portion of Holmes Road and William Street is densely populated and that there is significant City of Pittsfield and community opposition to this route segment variation (Exh. HO-C-6).[111]

The Company further asserted that potential construction impacts to trees located adjacent to the route, along both the

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108/ The Company noted that it would not be feasible to shore the trench sides in order to reduce trench width because trench shoring would be time consuming, costly, and would not significantly reduce the width of trenches or construction ROW's (Exh. HO-RR-36).

109/ The Company indicated that although it would prefer at least a 20-foot permanent ROW, a ten-foot ROW was the maximum the Company could negotiate in this area (Exh. HO-E-54). The Company added that part of this section of the ROW would be adjacent to an existing Berkshire 10-foot ROW (id.).

110/ The Company stated that it would not replant trees in order to (1) encourage the reestablishment of the herbaceous layer which would better stabilize the disturbed area, and (2) minimize costs of reclamation (Tr. 5, pp. 47-48).

111/ The Company noted that the City of Pittsfield has indicated that street opening permits would not be granted for construction along this segment variation and that any approved licenses or permits for this routing would be challenged (Exh. HO-C-6).

cleared ROW and roadways, would be avoided or minimized (Exhs. HO-E-30, HO-E-35; Tr. 5, p. 46). Berkshire stated that, although tree roots encountered within the trench alignment would be cut and removed, the trench would be located approximately 15 feet from standing trees along the cleared ROW, providing sufficient separation between the pipeline and any significant root systems (Tr. 5, p. 46). The Company also stated that although trees border the route along Old Tamarack Road, South Mountain Road, Holmes Road, William Street and along the property of Miss Hall's School, it would avoid removing any of these trees and would minimize construction impacts by: (1) trimming branches to provide adequate space for construction equipment and to avoid accidental breakage of tree limbs; (2) maintaining at least five feet between roadside trees and the pipeline; and (3) consulting with the tree warden or other appropriate officials in Pittsfield to determine the appropriate alignment of the pipeline within public ways to minimize tree impacts (Exhs. HO-E-30, HO-RR-35). The Company noted that it is unlikely that major root systems would be encountered during roadway construction in that large tree roots are not generally found within the compacted soil under roadways (Exh. HO-E-30). However, the Company agreed to replace any trees outside of the construction ROW damaged by construction (Exh. HO-RR-35).

The record indicates that construction of the meter station and proposed pipeline along the primary route would require the clearing of approximately seven acres of forest. In addition, the record indicates that the Company has attempted to minimize tree removal in off-street areas, where feasible, by restricting the width of the ROW and adjusting the alignment of the pipeline. The record further indicates that the Company would: (1) avoid removal of trees along the roadway portion of the route; (2) maintain adequate distance between the pipeline trench and adjacent trees; (3) employ measures to mitigate construction impacts to adjacent trees; and (4) replace any trees outside of the construction ROW damaged by construction.

Based on the foregoing, the Siting Council finds that construction of the proposed facilities along the primary route, with mitigation measures as described above, would have an acceptable impact on trees.

ii. Groundwater and Wells

The Company indicated that there are no public water supply source wells, and no surface water or aquifer protection zones within 100 feet of the primary route, but that there are six private wells within 100 feet of the primary route along Old Tamarack Road (Exh. HO-E-35). The Company asserted that since no blasting is anticipated for pipeline trench excavation along Old Tamarack Road, construction of the proposed pipeline would not impact the private wells (id.).[112] To verify that construction does not impact wells, the Company agreed to test these wells for pressure before and after construction (Exh. HO-E-62).

In addition, the Company maintained that construction of the proposed pipeline would not impact existing groundwater drainage patterns (Exhs. HO-E-36, HO-RR-35). The Company indicated that construction measures to preserve existing groundwater drainage patterns would include (1) installation of anti-seepage collars in the pipeline trench in sections where the backfilled trench could become a conduit for the subsurface flow of water, and (2) backfilling of the trench primarily with the same material excavated from the trench to minimize any difference between the soil backfilled in the trench and surrounding soil (id.).

The record indicates that no public water supply sources

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112/ The Company noted that it would install a municipal water line along Old Tamarack Road in conjunction with construction of the proposed pipeline, affording residents the opportunity to connect to the public water supply service (Exh. HO-E-62).

and only six private wells are in the vicinity of the primary route. Even though construction impacts to these wells would be unlikely, the Company will test the wells for pressure before and after construction. The record also indicates that construction techniques will ensure that existing groundwater drainage patterns are maintained after pipeline construction. Based on the foregoing, the Siting Council finds that construction of the proposed facilities along the primary route, with the mitigation measures described above, would have an acceptable impact on groundwater and wells.

iii. Wetlands and Surface Water

The Company asserted that although the proposed pipeline would cross streams and vegetated wetlands along the primary route, construction practices would minimize disturbance to wetlands and water bodies (Exh. HO-4, p. 3-2).

With regard to vegetated wetlands, the Company indicated that construction of the proposed pipeline along the primary route would require clearing of 7.1 acres of wetlands including 4.85 wooded acres and 2.2 open/shrub acres, located primarily within the Brattlebrook wetland system (Exh. BGC-5, p. 6).[113] However, the Company maintained that there would be no net loss of wetlands and that the crossing of wetlands would be carefully engineered such that impacts to vegetation, hydrology and soils would be avoided or minimized (id.).

The Company stated that vegetative clearing in wetlands would be kept to the minimum amount necessary and that the majority of wetlands construction within the Brattlebrook wetland system would take place within the ROW recently cleared by Tennessee to construct the NOREX facilities (Exhs. HO-4, pp. 3-3,

113/ Potential impacts to wildlife within the Brattlebrook wetland system are discussed in Section E.1.a.iv, below.

5-6, HO-E-39; Tr. 4, pp. 226-228).[114] The Company explained that the unstable nature of wetlands soils require wide trenches and construction ROW's and that decreasing the width of the trench or construction ROW would not be a feasible means of minimizing wetlands disturbance (Exhs. HO-E-9, HO-E-31).[115] However, the Company stated that (1) expeditious construction during the seasonal low-flow period, (2) general construction techniques and mitigation measures including sedimentation and erosion controls, restoration of ground contours, maintenance of tree stumps in the temporary workspace, and (3) specialized construction techniques specific to each resource area, would effectively minimize disturbance to wetlands (Exhs. HO-4, pp. 3-21 through 3-25, section 5, HO-E-31, HO-E-61).[116]

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114/ The Company indicated that of the 50 to 60 foot wide construction ROW that would be required, approximately 35 feet was cleared for the NOREX project (Exh. HO-E-9, Table 9-1, Tr. 4, p. 227). The Company further indicated that the existing permanent Tennessee ROW is 40 to 50 feet wide, that approximately 10 to 15 feet of this ROW will be used for temporary construction workspace and that the permanent Berkshire ROW will extend 20 to 25 feet beyond the Tennessee ROW (Exhs. HO-E-9, Table 9-1, HO-E-10, Table 10-1).

115/ The Company stated that, due to the unstable nature of wetland soils, trench excavation within wetlands would require gradual side slopes resulting in trench widths of 14 to 26 feet and overall construction ROW's of 50 to 60 feet (Exhs. HO-E-9, HO-E-31). The Company further stated that minimizing the ROW width for construction would not effectively reduce impacts because a narrower ROW would restrict equipment movement and increase construction time, therefore increasing the potential for erosion problems, sedimentation, and disruption of hydrology and soils (Exh. HO-E-54).

116/ The Company stated that, in the saturated wetland on either side of Brattle Brook where the trench cannot be dewatered, the pipeline would be put in place by the "push-pull" method (Exh. HO-4, p. 3-25). The Company explained that the push-pull method involves constructing the trench in a straight alignment, joining pipeline segments in an upland staging area, and guiding the pipeline into the trench by pushing from the upland staging area and pulling from the opposite end (id.). The Company noted that this method would minimize the number of

The Company indicated that the temporary workspace would be allowed to revegetate to pre-construction conditions but that the area directly over the pipeline, approximately 20 feet in width, would be kept permanently clear of mature woody vegetation (Exhs. HO-3, p. 6-59, HO-4, pp. 5-1, 5-6).[117] In addition, the Company stated that an environmental inspector would be employed to monitor compliance with all environmental regulations, that a wetlands biologist would be on-site during construction in wetland areas, and that construction work in wetlands would be subject to Orders of the Pittsfield Conservation Commission (Exhs. HO-4, pp. 5-1, 5-8, BGC-6).[118]

With regard to surface water, the Company indicated that the Housatonic River, four culverted streams under roadways, two intermittent streams in the vicinity of the Pittsfield Country Club, and two perennial and one intermittent stream in the Brattlebrook wetland system would be crossed by the primary route (Exhs. HO-4, pp. 3-2 through 3-17, HO-E-34). The Company asserted that impacts to the Housatonic River, culverted streams and intermittent streams would be avoided because: (1) the Housatonic River would be crossed entirely within an existing bridge utility bay; (2) the pipeline would be placed above or below roadway culverts; and (3) intermittent streams would be crossed during dry periods (Exh. HO-4, pp. 3-2 through 3-17, 3-23).

With regard to the two perennial streams within the

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vehicle passes over the wetland surface (id.).

117/ The Company indicated that it would monitor ROW revegetation for at least two growing seasons, that ROW management would be coordinated with Tennessee, and that no herbicides would used for ROW maintenance (Exh. HO-4, pp. 5-6, 6-2, HO-RR-34).

118/ The Company submitted its Notice of Intent to the Massachusetts Department of Environmental Protection and Pittsfield Conservation Commission in March 1992 (Exh. HO-RR-30).

Brattlebrook wetland system, the Company maintained that impacts would be minimized by (1) construction of the pipeline under flume pipes which would temporarily carry stream flows, and (2) a comprehensive erosion and sedimentation control plan which would prevent siltation within streams (Exhs. HO-4, pp. 3-23, 3-24, BGC-2, Attach. A).

The record indicates that construction of the proposed pipeline along the primary route would impact approximately seven acres of wetland resources but that impacts to wetland vegetation, soils and hydrology would be minimized by constructing largely within a recently cleared pipeline ROW and by expeditious scheduling of construction during periods of low water flow. The Company also would utilize specialized construction techniques to minimize disturbance and restore wetlands to pre-construction conditions to the greatest extent possible. In addition, construction within wetland resource areas would be supervised by an environmental inspector and wetlands biologist and will be subject to Orders of Condition of the Pittsfield Conservation Commission.

The record further indicates that construction of the proposed pipeline would avoid impacts to most water bodies along the route because construction would take place above or below existing culverts and, in the case of the Housatonic River, within an existing bridge utility bay. Where water bodies would be directly crossed, impacts would be minimized by the timing of construction during dry periods, use of flume pipes and sedimentation and erosion controls.

Based on the foregoing, the Siting Council finds that construction of the proposed facilities along the primary route, with mitigation measures as described herein, would have acceptable impacts to wetland resources and surface water.

iv. Wildlife

The Company indicated that the primary route would traverse the habitat of rare species in the northern portion of the Brattlebrook wetland system and also would be located close to nesting habitat within Canoe Meadows (Exhs. HO-4, p. 3-26, HO-RR-29, updated sup.).

The Company explained that the wetland area north of Brattlebrook Park is designated as "estimated habitat" for two rare wetland wildlife species, the wood turtle and American bittern, which are state-designated species of special concern (Exhs. HO-3, Tables 7-1, 7-2, HO-4, p. 3-26).[119] The Company noted that recorded locations of these species away from the proposed construction ROW makes it unlikely that these species would be impacted during construction (Exh. HO-4, p. 3-26). However, the Company asserted that construction timing during the seasonal low flow period from summer to early fall as well as careful construction procedures would minimize any potential disturbance (Exh. HO-4, pp. 3-26, 3-28).

With regard to the wood turtle, the Company indicated that although the construction time-frame would avoid the wood turtle's aquatic and hibernating phases, it would coincide with the wood turtle's terrestrial phase where there is potential for individuals to migrate long distances (id., pp. 3-26, 3-28). In order to protect transient wood turtles, the Company stated that it would (1) inspect the work area prior to construction and daily during construction for wood turtles and move them to adjacent suitable habitats outside the construction ROW, and (2) install siltation barriers on either side of the construction ROW during construction to deter potential wood turtle access

119/ The Company indicated that a species of special concern is a Massachusetts rare species that has been documented to be suffering a decline that could threaten the existence of the species in Massachusetts if allowed to continue unchecked (Exh. HO-3, p. 7-4).

(id., p. 3-28).[120] The Company also stated that post-construction impacts would be minimized by (1) restoration of the area to pre-construction conditions resulting in no permanent loss of wood turtle habitat, and (2) modification of siltation barriers to allow wood turtle migration across the ROW (id., p. 29).[121] With regard to the American bittern, the Company stated that construction during the low flow period would avoid the nesting season but would coincide with rearing of young chicks (id., pp. 3-26, 3-28). However, the Company noted that, based on field inspections, it is unlikely that any American bittern nests would be encountered within the work space (id., p. 3-28). The Company stated that a field inspection will be conducted prior to construction and, if nests are found within the construction ROW, the Company will proceed in accordance with recommendations from the Massachusetts Natural Heritage Program (id., p. 3-28; Tr. 5, p. 105).

In addition, the Company noted that a portion of Canoe Meadows, to the east of the proposed pipeline route, contains bobolink nesting habitat (Tr. 5, pp. 96-97). The Company indicated that, although the nesting habitat is not directly within the pipeline ROW, it would avoid the nesting period by deferring construction in this area to the fall (id., p. 97).

The record indicates that the primary route would traverse the habitat of two rare species and would also be located in the vicinity of additional nesting habitat. However, the Company

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120/ The Company stated that Tennessee followed these same construction procedures when constructing the Tenneco interconnect in this habitat area and successfully avoided impacts to rare species (Exh. HO-4, pp. 3-28, 3-29).

121/ The Company indicated that siltation barriers would remain in place until revegetation is established (Exh. HO-4, p. 3-29). In order to allow wood turtle migration across the ROW, the Company would create breaks in the siltation barrier and install a second siltation barrier one foot in front of each break (id.).

will time construction to minimize impacts to wildlife, and also will monitor the construction ROW to avoid impacts. In addition, the Company will consult with appropriate wildlife agencies if necessary.

Based on the foregoing, the Siting Council finds that construction of the proposed facilities along the primary route, with mitigation measures as described herein, would have an acceptable impact on wildlife.

b. Land Use, Traffic/Roadways and Safety

i. Land Use

The Company indicated that the construction of the proposed pipeline and meter station along the primary route would potentially impact sensitive receptors including residences and a school, as well as recreational, agricultural and cultural resources located along the route (Exhs. BGC-5, HO-E-11, HO-E-12, HO-4, pp. 2-6, 4-3).

With regard to residential impacts, the Company indicated that fifteen residences would potentially be within 50 feet of the pipeline construction (Exh. HO-E-24). The Company agreed that residents have legitimate concerns in requesting that their distance from the pipeline facilities be maximized (Tr. 4, pp. 189-190).[122] The Company agreed to install the pipeline a minimum of 20 feet from all residences, but stated that it would attempt to maximize the distance between structures and the pipeline, and, where possible, maintain at least a 50-foot separation between the pipeline and residential structures (Exh. HO-RR-35; Tr. 5, pp. 40-41).[123] The Company added that it

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122/ See Section E.1.b.iii, below for a discussion of safety issues.

123/ For instance, the Company indicated that it would construct the pipeline on the south side of William Street where the residences are located further from the street than the residences on the north side of the street (Tr. 4, pp. 193-195).

would attempt to weld pipeline segments away from residential areas, thereby minimizing construction noise (Tr. 5, p. 42).

The Company noted that the approximately two acre meter station site is located within a residentially zoned area but that the closest residence is located more than 200 feet to the west of the site (Exhs. HO-E-8, BGC-2, Attach. B, p. 8, HO-SC-AL-10, exhibit 1).[124] The Company provided that a wooded buffer would be maintained on all sides of the meter station within the site boundary (Exh. BGC-2, Attach. B, p. 8, Exh. HO-SA-AL-10, exhibit 1).

On June 24, 1992, Berkshire indicated that test borings have shown that there is ledge present at the meter station site and that, depending on the extent of the ledge, blasting and/or mechanical excavation measures would be used to remove the ledge (Exh. HO-E-64, sup.). The Company noted that the entire meter station site consists of approximately two acres but that only 2,000 square feet would be required for the structures (Exhs. HO-2, pp. 8-9, SC-AL-10, Exh. 1).

In addition, the Company indicated that although the primary route would traverse the property of Miss Hall's School, all construction would take place when school is out of session (Exhs. HO-4, p. 5-14, SC-AL-6).[125]

With regard to recreational resources, the Company indicated that the primary route would traverse four private/public recreation areas, the Bousquet Ski Area, the

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124/ With respect to the meter station site, Berkshire and Tennessee have petitioned the DPU for an exemption from certain provisions of the City of Pittsfield zoning ordinance (Exh. HO-E-51).

125/ Berkshire stated that construction could take place either during the summer or Thanksgiving recess but that summer construction would be preferable (Exh. HO-AS-AL-6). The Company identified a noticed route realignment along Kris Lane that would avoid school property but stated that such realignment would not be preferable because it would entail additional roadway construction and negotiation with additional landowners (id.).

Pittsfield Country Club, Canoe Meadows, and Brattlebrook Park (Exh. HO-4, pp. 2-6, 5-14). However, the Company asserted that impacts to the Bousquet Ski Area, Pittsfield Country Club and Canoe Meadows would be minimized by the scheduling of all construction and restoration work such that interference with recreational activities would be minimized (Exhs. HO-4, p. 5-14, HO-SC-AL-7).[126] With regard to Brattlebrook Park, the Company stated that, in exchange for an easement through a portion of the park, the Company has agreed to donate a 40 acre parcel to the City of Pittsfield in order to expand the park (Exh. HO-4, p. 2-7).[127]

With regard to agricultural resources, the Company stated that the primary route would traverse agricultural fields and community gardens within Canoe Meadows (Exh. HO-4, p. 5-14; Tr. 5, p. 97). However, the Company indicated that construction would be deferred until mid October to avoid interference with the planting and harvesting of crops (Tr. 5, p. 97).[128] In addition, the Company indicated that the Audubon Society has requested that the depth of cover over the pipeline in the agricultural area be increased to five feet (Exh. HO-RR-29, updated sup.).

With regard to cultural resources, the Company identified

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126/ The Company noted that construction within the Bousquet Ski Area would take place during July and August (Exh. HO-SC-AL-7). The Company originally anticipated construction within the Pittsfield Country Club and Canoe Meadows to take place in the early spring but indicated that it could construct in these areas after October 15th (Exhs. HO-4, p. 5-14, HO-RR-33).

127/ The Company noted that required approvals for the Brattlebrook Park easement have been obtained from the Pittsfield City Council and State Legislature (Exh. HO-4, p. 2-7).

128/ The Company noted that this construction time-frame also would avoid interference to bird nesting within Canoe Meadows. See Section E.1.a.iv, above.

six historic sites and one archaeological site within 100 feet of the primary route (Exh. HO-E-11; Tr. 5, p. 24). The Company indicated that all historic sites would be located at least 50 feet from the proposed pipeline, and, as such, would not be impacted by construction (Exh. HO-4, p. 5-12; Tr. 5, pp. 25-26). The Company further indicated that, after consultation with the Massachusetts Historical Commission ("MHC"), it had adjusted the centerline of the pipeline along a portion of the route in a wooded area of the Pittsfield Country Club in order to avoid three small prehistoric sites which were located within the original ROW (Exh. HO-4, pp. 3-30, figure 3-9). In order to avoid inadvertent encroachment onto the archaeological sites, the Company indicated that the MHC also has requested that the Company: (1) maintain a minimum ten-meter buffer zone between the archaeological sites and any areas of construction-related activities; (2) specify no access to the site areas on the construction documents; and (3) erect a fence prior to the commencement of any site preparation or construction activities (Exh. HO-RR-29, updated sup.).

The record also indicates that there is ledge present on the meter station site. However, the Company has not determined the extent of the ledge or whether they would be able to remove it by mechanical means rather than by blasting. The Siting Council notes that the two acre meter station parcel is large enough to accommodate some adjustment of the layout of the meter station structures, which will require only 2,000 square feet, so that blasting can be avoided to the greatest extent possible.

The record indicates that the primary route passes near residences and a school, historic resources and also traverses a number of recreational areas as well as one agricultural area. In addition, the meter station will be constructed in a residential area. However, the record further indicates that the Company's construction schedule and construction techniques will avoid or minimize potential impacts. The Company will attempt to maximize the separation between residences and the proposed facilities and will maintain a tree buffer around all sides of the meter station. The construction schedule has been carefully planned to avoid interference with school, recreational and agricultural activities and, upon consultation with the MHC, the Company has realigned the centerline of the pipeline to avoid prehistoric sites. Compliance with additional recommendations of the MHC and the Audubon Society will further ensure that construction of the proposed facilities does not impact prehistoric sites or agricultural resources.

Based on the foregoing, the Siting Council finds that the construction of the proposed facilities along the primary route, with mitigation measures as described herein, would have an acceptable impact on land use.

ii. Traffic/Roadways

The Company indicated that construction of the proposed pipeline along the primary route would require approximately two and one half miles of parallel construction adjacent to the roadway layout, plus additional road crossings (Exh. HO-E-15, Table 15-1). However, the Company asserted that temporary disruption of traffic in the vicinity of ongoing construction would be minimized by maintenance of at least one lane of traffic during roadway construction (Exhs. HO-4, p. 3-30, HO-E-16, HO-E-38).[129] The Company noted that although one roadway, Old Tamarack Road, would be closed to traffic during construction to

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129/ The Company noted that a 30-foot workspace would be required for roadway construction and, as such, there is adequate workspace in all roadways (Exhs. HO-E-37, HO-E-38). The Company explained that roadway construction requires a narrower construction workspace than cross-country construction because: (1) the trench width at the surface can be narrower; (2) it is possible to work closer to the edge of the trench; and (3) the clearing on both sides of the roadways allows adequate swing room for operation of cranes and other equipment (Exhs. HO-E-37, HO-E-38).

install a new waterline in conjunction with the proposed pipeline, alternate traffic routes would be established and access to residences would be maintained during construction (Exh. HO-E-56).[130]

The Company indicated that Old Tamarack Road would be repaved curb-to-curb and that all other roadway surfaces would be patched to the standards of the Pittsfield Department of Public Works (Exh. HO-E-60). The Company added that, following initial roadway resurfacing, it would monitor the condition of all roadways for two years and repair any subsequent settling, and also repair or reimburse affected property owners for any damage to existing utilities as a result of roadway excavation (Exhs. HO-E-19, HO-RR-35).

The record indicates that temporary construction impacts to the traffic flow will be minimized by maintenance of at least one lane of traffic during construction on all roadways, excepting Old Tamarack Road. Where Old Tamarack Road will be closed to traffic during construction, the Company will establish alternate traffic routes and provide residential access. The record further indicates that the Company will ensure that the condition of the roadways is not impaired by pipeline construction.

Based on the foregoing, the Siting Council finds that the construction of the proposed facilities along the primary route, with mitigation measures as described herein, would have an acceptable impact on roadways and traffic.

iii. Safety

The Company asserted that risk of natural gas pipeline

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130/ The Company stated that as part of its easement agreement with the owners of the Bousquet Ski Area, it had agreed to install a water line on Old Tamarack Road and that construction of both the water line and pipeline would require use of the full width of the established roadway layout (Exh. HO-E-56; Tr. 4, p. 57).

accidents is extremely low and that the design, installation and operation of the proposed pipeline will ensure that it will be constructed and operated in a safe and reliable manner (Exh. HO-E-49; Tr. 1, pp. 157-159, Tr. 3, pp. 68-69; Berkshire/Altresco Initial Brief, p. 75-77). The Company stated that design features of the proposed pipeline would meet or exceed required minimum federal safety standards (Exh. HO-1, p. 4-1; Tr. 1, pp. 115-120).[131] The Company further asserted that damage to its system usually results from third party excavation, and that therefore it had incorporated measures to protect the pipeline from accidental damage, including: (1) use of heavy wall thickness pipe; (2) installation of the pipeline three to four feet below the surface; (3) installation of a highly visible warning tape above the pipeline for its entire length; and (4) Company participation in Dig Safe, a program that requires contractors to register all excavation related activity prior to construction (HO-E-48).[132] In addition, the Company stated that operation of the pipeline would be monitored continuously by electronic equipment and that three isolation valves, which would segment the pipeline in the event of any pipeline malfunction, would be installed along the route (Exhs.

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131/ The Company explained that federal regulations regarding certain aspects of pipeline design, including materials, wall thickness and pressure, vary according to the classification of the population density along the pipeline route (Tr. 1, pp. 118-9). The Company noted that the pipeline has been designed for the most restrictive classification, multi-story buildings, even though the pipeline traverses less restrictive classifications for its entire route (id., pp. 119-120).

132/ The Company stated that although the state code requires three feet of cover for the pipeline, it would attempt to attain four feet of cover along the route (Tr. 1, pp. 133-134). The Company further stated that, based on preliminary engineering, the pipeline would be buried three feet or less in one location where it would cross over a culvert, and that a concrete cap would be placed over the pipeline in this location to provide mechanical protection to the pipeline (HO-RR-14, Tr. 1, p. 140).

HO-E-41, HO-E-47; Tr. 1, pp. 164-171).[133] Finally, the Company stated that the pipeline would be cathodically protected to prevent erosion and that the pipeline route would be periodically inspected by Company personnel (Exh. HO-E-47; Tr. 1, pp. 172-174).

The Company also asserted that safety features would be incorporated into the design and operation of the meter station, including: (1) utilization of fire-proof and fire-resistant materials and explosion-proof equipment; (2) operation of piping systems below design pressure ratings; and (3) installation of gas and fire detection systems (Exh. AL-RR-1). The Company further stated that the meter station facilities would be manually inspected on a weekly basis, safety and operating conditions would be continuously monitored by electronic equipment and public access to the meter station area would be restricted (id., Exh. HO-RR-27).

In addition, the Company specifically agreed to implement the following procedures: (1) to develop appropriate emergency response plans for possible accidents or related contingencies resulting from operation of the pipeline in cooperation with appropriate federal, state and local officials, and provide a copy of such plans to the Siting Council prior to operation of the pipeline; (2) to publish emergency response plans and procedures in a brochure to be mailed or delivered to all property owners and residents abutting the route, and, if requested, hold public educational forums, prior to the operation of the pipeline; (3) to implement the pipeline safety features as

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133/ Berkshire indicated that above-ground valve stations would be located at the proposed meter station and at the Altresco facility (Exh. HO-E-41). The Company stated that a third valve station would be located at the mid-point of the route, on the side of the road near the entrance to Canoe Meadows (id., Tr. 1, p. 168). The Company added that this valve station would be installed below-grade in a concrete vault but would require a small, above-ground cabinet to house telemetry equipment (Exh. HO-E-41; Tr. 1, pp. 167-168).

presented in the record, including: (a) the installation of pipeline warning tape and above-ground markers; (b) the installation of a 24-hour flow monitoring and automatic shut-off valve system; and (c) the performance of regular inspections of the pipeline route to detect any leaks and to monitor construction activity by outside parties; (4) after consultation with appropriate local officials, to select a style, material and color for above-ground pipeline markers that is aesthetically acceptable, and provide vegetative screening on all sides of all above-ground valve facilities; and (5) to make available for public inspection at Berkshire's offices a plan of the exact location of the pipeline, indicating the depth of the pipeline and showing locations of abutting property lines and existing utility, water and sewer lines (Exh. HO-RR-16).[134]

Motyl/Clerici assert that pipeline failures cannot be avoided entirely and that the safety concerns of the neighborhood in the vicinity of the meter station have not been addressed (Motyl/Clerici Initial Brief, pp. 53-56). Motyl/Clerici question the effectiveness of the Company's participation in Dig Safe and the reliability of its monitoring system (id.). In addition, Motyl/Clerici state that, upon construction of the proposed facilities, seven residences would be "pinned" between two metering stations in the immediate vicinity of three natural gas pipelines, and, thus, in the event of a meter station or pipeline accident, would have no escape route (id., p. 54).

The record indicates that the Company has incorporated extensive safety and monitoring features into the design of the proposed pipeline as well as safeguards to protect the pipeline from accidental third-party damage. In addition, the Company will develop, in cooperation with federal, state and local officials, emergency response plans for potential pipeline

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134/ The Company agreed to implement these procedures that were included in the 1990 Berkshire Decision (Phase II) (Exh. HO-RR-16).

accidents.

With regard to Motyl/Clerici's concerns regarding safety of the residents in the vicinity of the proposed meter station, there is no evidence in the record that location between the two metering stations would present any increased safety hazards. However, the Company's emergency response plan should specifically address evacuation procedures, including any special provisions warranted by the presence of multiple facilities, in the event of a pipeline or meter station accident potentially affecting the residences located between the Knox Road and proposed Bousquet meter stations.

Based on the foregoing, the Siting Council finds that construction of the proposed facilities along the primary route, with all proposed safety features, would have acceptable safety impacts.

2. Environmental Impacts of the Primary Route Segment Variations

a. Description

The Company stated that variations to certain portions of the primary route were considered to address specific environmental, regulatory or other potential impediments, or concerns, including potential difficulties in obtaining easements from certain landowners along the route (Exh. HO-1, pp. 5-34 through 5-36; Tr. 4, pp. 229, 231, 248, 256, 258-259).[135] Berkshire asserted that the environmental impacts of each of the route segment variations would be acceptable and comparable to the corresponding segments of the primary route (Exh. HO-1,

135/ The Company indicated that it has obtained options for easements for all portions of the route with the exception of the Canoe Meadows crossing (Tr. 4, p. 260). With regard to the Canoe Meadows crossing, the Company indicated that the Massachusetts Audubon Society has agreed to the terms and conditions of a license agreement but that said agreement has not yet been completed (id., pp. 260-261; Exh. HO-RR-28).

pp. 5-36, 5-37). In support, Berkshire provided an analysis of the environmental impacts of each route segment variation to the corresponding portion of the primary route (id., appendix F; Exh. HO-RR-25). Berkshire noted that the route segment variations were not approved by the Task Force (Exh. HO-1, pp. 5-36, 5-37).

The Company stated that route segment variation 3b would travel cross-country between South Mountain Road and the Pittsfield Country Club, thereby eliminating the majority of the proposed construction within the roadway layout of South Mountain Road (Exhs. HO-1, Figure 5-5, HO-E-15).[136] By avoiding a portion of South Mountain Road, the Company stated that construction across one roadway culvert and within 50 feet of 11 residences along South Mountain Road would be avoided (Exhs. HO-1, Figure 5-5, HO-E-24). However, the Company stated that construction of this route segment variation would require blasting of bedrock and also would impact more wooded wetlands and forest resources than the corresponding segment of the primary route (Exh. HO-RR-25; Tr. 4, pp. 242-245). In addition, the Company noted that this route segment variation would be aligned within 100 feet of a day care center (id.).

The Company stated that route segment variation 4b was an alternative route through the Pittsfield Country Club that would follow an existing golf cart path and also would avoid construction across property owned by Miss Hall's school (Exh. HO-1, p. F-3; Tr. 4, p. 245).[137] The Company indicated that this route segment variation would be longer than the

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136/ The Company indicated that route segment variation 3b initially was suggested by a landowner who had concerns regarding potential impacts to residences and a culverted stream within South Mountain Road (Tr. 4, p. 243).

137/ Berkshire stated that this route segment variation was included in the event easements could not be negotiated with the owners of Miss Hall's School or residents of Kris Lane (Tr. 4, p. 245).

corresponding segment of the primary route but would have less impact on forest resources (Exh. HO-RR-25). However, the Company stated that this route segment variation would have greater residential impacts, require relocation of an existing gas pipeline and cross railroad tracks located within difficult terrain (Exhs. HO-RR-25, HO-E-24; Tr. 4, pp. 245-246).

With regard to the pipeline crossing of Canoe Meadows, the Company stated that it had considered three route segment variations (Exhs. HO-1, Figure 5-5, HO-RR-25). The Company noted that the primary route, which would follow the northern periphery of Canoe Meadows and exit the sanctuary onto William Street, was the path preferred by the Audubon Society (Exh. HO-RR-25; Tr. 4, pp. 250-251).[138] The Company stated that (1) route segment variation 6a would travel straight across the north central portion of the sanctuary;[139] (2) route segment 6b would avoid construction within Canoe Meadows completely and travel, instead, along Holmes and William Streets, and (3) route segment 6d would cross the northern periphery of the sanctuary and then turn to the south to exit onto New Lenox Road instead of William Street (Exhs. HO-1, Figure 5-5, HO-RR-25; Tr. 4, pp. 249-253). In comparing the Canoe Meadows route variations, the Company stated that route segment variation 6b would have significantly greater residential impacts than any of the other route segments,[140] and

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138/ The Company noted that the Department of Food and Agriculture's Bureau of Land Use also supported the primary route in comparison to all other route segment variations (Tr. 4, p. 251).

139/ The Company indicated that route segment variation 6a was originally proposed as the preferred segment variation (Exh. HO-RR-25).

140/ The Company noted that this route segment variation was included in the event the Company could not negotiate an easement with the Audubon Society (Tr. 3, p. 46). The Company added that this segment was part of the route approved in the 1990 Berkshire Decision (Phase II), and that there is significant community opposition to this segment (Tr. 4, p. 192). see that route segment variation 6d was longer than the other route segments and would involve potentially difficult construction within a narrow roadway (Exhs. HO-1, Figure 5-5, HO-C-6). The Company stated that variation 6a would have fewer impacts to sensitive receptors and historical resources than the primary route, but would traverse a portion of the sanctuary that would likely be reforested under the Audubon Society's long-term management plan (Exhs. HO-1, p. F-4, HO-RR-25; Tr. 4, pp. 250-251).[141]

The Company stated that route segment variation 7b would follow Elm Street rather than travelling cross country from the eastern end of Williams Street to the existing Tennessee ROW (Exh. HO-1, Figure 5-5).[142] The Company noted that route segment 7b would have significantly greater impacts to sensitive receptors and slightly greater impacts to forest resources (Exhs. HO-E-24, HO-RR-25; Tr. 4, pp. 256-257).

The Company stated that route segment variation 8b was included as an alternative to the crossing of Brattlebrook Park (Exh. HO-RR-25). However, the Company stated that this segment would be significantly longer than the primary route segment and would impact forest resources, wetlands and wildlife habitat to a greater degree (Exh. HO-RR-25).

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Section E.1.a.i, above.

141/ The Company indicated that there are three residences located within 100 feet of the pipeline along route variation segment 6a and 21 residences and one historic structure located within 100 feet of the pipeline along the corresponding portion of the primary route (Exhs. HO-RR-25, HO-E-11). The Company added that there are no residences or historic structures located within 50 feet of either route (Exh. HO-E-24; Tr. 5, pp. 25-26). In addition, the Company noted that alignment of the pipeline within Williams Street would maximize distance from residences (Tr. 4, pp. 193-195). see Section E.1.b.i, above.

142/ The Company indicated that this segment was included in the event easements could not be negotiated for the primary route (Tr. 4, p. 256).

b. Analysis

The record indicates that the Company included variations to certain portions of the primary route, primarily to provide the Company with options in the event easement agreements could not be negotiated with specific landowners. The record further indicates that, the environmental impacts of the route segment variations would, for the most part, be comparable to the environmental impacts of the primary route. By incorporating the mitigation measures discussed in Section E.1, above, construction along each of the route segment variations would be acceptable.

However, the record also demonstrates that, although a number of the route segment variations have advantages with regard to specific environmental impacts, none of the route segment variations is clearly preferable to the corresponding portion of the primary route, with respect to overall environmental impacts.

Based on the foregoing, the Siting Council finds that the construction of the proposed facilities along the primary route is preferable to construction along the primary route with any of the segment variations with respect to environmental impacts.

3. Environmental Impacts of the Alternative Route

a. Land and Water Resources

Berkshire provided estimates of impacts to land and water resources of the construction of the proposed pipeline along the alternative route (Exhs. HO-E-29, HO-E-34, HO-E-35, HO-E-39, HO-E-44, HO-S-20, Tables S-20-2, S-20-3). The Company indicated that construction of the proposed pipeline along the alternative route would require (1) clearing of nearly 17 acres of forest of which 7.2 acres would be upland forest, and (2) traversing 11.7 acres of vegetated wetlands, including 9.5 wooded acres and 2.2 open/shrub acres (Exh. HO-S-20, Table S-20-3). The Company indicated that, with the exception of one wetland area located along Dan Fox Drive, all wetland resource areas that would be cleared are adjacent to the ROW recently cleared by Tennessee during construction of the NOREX facilities (Exhs. HO-E-10, HO-E-39, Table 39-2). The Company further indicated that the alternative route would follow the same path through the Brattlebrook wetlands system as the primary route but that the alternative route also would traverse wetlands associated with the Housatonic River and Canoe Meadows (Exh. HO-E-39).[143]

With regard to surface water and water supply, Berkshire indicated that construction of the alternative route would require a crossing of the Housatonic River, three intermittent stream crossings and four perennial stream crossings, including three crossings of Sackett Brook, a perennial stream within the wetland portion of Canoe Meadows (Exhs. HO-E-34, HO-E-63). The Company stated that, to avoid contamination problems, the Massachusetts Department of Environmental Protection would require the Company to bore under the Housatonic River (Exh. HO-E-57). In addition, the Company indicated that there are no private wells located along the alternative route, and that there are no public water supply wells or designated surface water or aquifer protection zones within the vicinity of the route (Exh. HO-E-35).

With regard to wildlife, the Company stated that the alternative route also would cross the estimated habitat for the wood turtle and American bittern in the wetland area north of Brattlebrook Park. see Section E.1.a.iv, above. The Company indicated that there is additional habitat suitable for the wood turtle along the alternative route in the vicinity of the Housatonic River and Sackett Brook and their associated wetlands systems (Exh. HO-63). The Company also indicated that there is state designated vegetative community of special concern along

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143/ The Company stated that the Massachusetts Audubon Society has indicated that it would not negotiate for an easement to construct the pipeline through wetlands within Canoe Meadows (Exh. HO-E-63).

the alternative route, to the east of Dan Fox Drive (Exhs. HO-E-9, HO-E-45, HO-3, pp. 7-5 through 7-10).

Finally, the Company explained that blasting would be required to construct the proposed pipeline along the alternative route due to an outcrop of bedrock in the southern portion of the Pittsfield Country Club (Exh. HO-E-27).

The record demonstrates that construction of the proposed facilities along the alternative route would impact forest resources, wetlands resources, surface water, and wildlife habitat. However, the Company's comprehensive mitigation strategies discussed with reference to construction of the proposed facilities along the primary route also would serve to mitigate impacts along the alternative route. Although the Housatonic River is contaminated where it would be crossed by the alternative route, boring the pipeline under the river would minimize potential impacts. Further, although there are considerable wetlands and a number of associated stream crossings in the vicinity of Canoe Meadows and the Housatonic River crossing, this routing has been used in the past for construction of the North Adams lateral.

The record also demonstrates that additional impacts of the construction of the proposed facilities along the alternative route relate to blasting that would be required in one area of bedrock outcrop and the crossing of a vegetative community of special concern. The Siting Council notes that state and local regulations would require blasting to be carried out in a safe and controlled manner. The Siting Council further notes that alignment of the pipeline close to the roadway layout of Dan Fox Drive as well as utilization of specialized construction techniques could potentially minimize impacts to the vegetative community of special concern.

Based on the foregoing, the Siting Council finds that construction of the proposed facilities along the alternative route, with mitigation measures, would have acceptable impacts to land and water resources.

b. Land Use, Traffic/Roadways and Safety

The Company estimated the impact of construction of the proposed facilities along the alternative route with regard to land use, traffic/roadway and safety concerns (Exhs. HO-E-11, HO-E-12, HO-E-15, HO-E-24, HO-E-27, HO-S-20, Tables S-20-1, S-20-2). The Company stated that land use along the alternative route includes recreational, residential, and conservation uses (Exh. HO-E-9, Table 9-2). The Company stated that impacts to recreational areas would be minimized by the timing of construction (Exh. HO-E-63). The Company stated that eight residences would potentially be located within fifty feet of the pipeline route, and that no historic sites, archaeological sites or schools would be located in the vicinity of the route (Exhs. HO-E-11, HO-E-12, HO-E-24). The Company further stated that construction work in roadways would involve only roadway crossings, the majority of which would be bored in order to reduce traffic impacts (Exhs. HO-E-18, HO-E-58). With regard to safety, the Company did not identify any proposed design, installation or operational features that would vary according to the location of the facilities.

The record indicates that impacts to recreational facilities would be mitigated by timing of construction, that impacts to residences would be mitigated by use of the same construction techniques proposed by the Company with regard to the primary route, and that traffic impacts would be minimal. The record further indicates that the safety features of the proposed facilities would not vary according to the route chosen.

Based on the foregoing, the Siting Council finds that the construction of the proposed facilities along the alternative route, with mitigation measures, would have acceptable impacts with regard to land use, traffic/roadways and safety.

4. <u>Conclusions on Environmental Impacts</u>

The Siting Council has found that the construction of the proposed facilities along the primary and alternative routes would have acceptable impacts with regard to water and land resources and acceptable impacts with regard to land use, traffic/roadways and safety. The Siting Council also has found that the primary route is preferable to the primary route with any of the segment variations with respect to environmental impacts.

In comparing the primary and alternate routes, the record indicates that the primary route would be constructed in the vicinity of a greater number of sensitive receptors including residences, a school and historic and archaeological resources, and also would have greater impacts to traffic and roadways. Specifically, the primary route would be located within fifty feet of eight more residences than the alternative route and would involve approximately 2.5 miles of roadway layout construction while the alternative route would involve only roadway crossings.

However, the record also indicates that such impacts, for the most part, would be construction-related and temporary, and would be minimized by the Company's commitment to appropriate construction techniques and mitigation measures. In addition, the Company will attempt to maximize the distance between the pipeline and residences. The Company also has agreed to significant design, installation and operational features to help ensure the safe operation of the pipeline facilities, and also will establish detailed emergency procedures.

With respect to natural resource concerns, the record demonstrates that the most significant environmental impacts of both routes would be the permanent loss of forests and wetland resources. The primary route would impact approximately seven acres of forest and seven acres of wetlands while the alternative route would impact approximately 17 acres of forest and 12 acres of wetlands. Although construction-related impacts to both forests and wetland resource areas would be minimized by a variety of construction techniques and mitigation measures, forest and wetland vegetation would be permanently altered because the permanent ROW, directly over the pipeline, would be maintained clear of tall-growing woody vegetation. In addition, although a portion of the initially cleared forested areas would be allowed to revegetate to pre-construction conditions, the forest would not be reestablished for at least twenty years.

Consequently, overall, the primary route would involve greater impacts with respect to land use, traffic/roadways and safety, while the alternative route would involve greater impacts with respect to land and water resources. The Company would incorporate design, installation and operational procedures, as well as mitigation measures and procedures during construction, to minimize impacts in both the above categories. Nonetheless, some level of impact or risk, however small, must be recognized in each of the respective categories, and the offsetting advantages of the two routes with respect to different categories must be balanced, in order to determine the environmentally preferable route.

Given the approximate six mile length of both routes, there is not a significant difference in the number of residences within 50 feet of the pipeline. Considering, further, the temporary nature of construction impacts and the low risk of pipeline accidents, any advantage of the alternative route with respect to land use, traffic/roadways and safety is minimal.

With respect to land and water resources, however, the alternative route would result in the loss of 17 acres of forest and affect 12 acres of vegetated wetlands -- levels approximately twice those of the primary route. Moreover, much of the additional wetland impact would occur in the sizeable area in the vicinity of the Housatonic River/Canoe Meadows with the associated multiple crossings of Sackett Brook. Finally, although this routing has been previously used for the North Adams lateral, Canoe Meadows is a designated conservation area.

Based on the foregoing, the Siting Council finds that construction of the proposed facilities along the primary route would be preferable to construction along the alternative route with respect to environmental impacts.

F. Conclusions on the Proposed and Alternative Facilities

The Siting Council has found that the Company considered a reasonable range of practical siting alternatives.

The Siting Council has found that construction of the proposed facilities along the primary route is preferable to construction along the alternative route and to construction along the primary route with any of the segment variations with respect to cost.

The Siting Council has found that construction of the proposed facilities along the primary route is preferable to construction along the primary route with any of the segment variations with respect to environmental impacts. The Siting Council also has found that construction of the proposed facilities along the primary route and alternative route is acceptable with respect to environmental impacts. The Siting Council has further found that construction of the proposed facilities along the primary route is preferable to construction along the alternative route with respect to environmental impacts.

Accordingly, the Siting Council finds that construction of the proposed facilities along the primary route is superior to construction along the alternative route and to construction along the primary route with any of the segment variations.

IV. DECISION

The Siting Council hereby APPROVES the petition of the Berkshire Gas Company to construct (1) a 6.2 mile, 500 pound per square inch natural gas pipeline along the primary route, and (2) a meter station at the primary site, subject to the following CONDITIONS:

(1) consult with the tree warden or other appropriate officials in Pittsfield to determine the appropriate alignment of the pipeline within public ways such as to minimize any tree impacts;

(2) utilize the following mitigation measures during construction of the pipeline in order to minimize impacts to trees along the pipeline route: (a) maintain at least 15 feet between the pipeline trench and standing trees along the cleared ROW; (b) maintain at least five feet between the pipeline trench and roadside trees; (c) trim tree branches to provide adequate space for construction equipment and to avoid accidental breakage of tree limbs;

(3) replace roadside trees and trees outside the construction ROW damaged as a result of pipeline construction, as determined by the Pittsfield tree warden or other appropriate official, and restore all landscaping, shrubbery and driveways along the roadway portion of the pipeline alignment to pre-construction conditions;

(4) install anti-seepage collars in the pipeline trench as necessary in order to maintain groundwater drainage patterns existing prior to construction;

(5) implement the mitigation measures and specialized construction techniques to minimize disturbance to wetland

resource areas as presented in the record, including (a) construction during the seasonal low-flow period, and (b) utilization of erosion and sedimentation controls;

(6) inspect the construction work area prior to construction and daily during construction for wood turtles and if found, remove them to adjacent suitable habitats outside the construction ROW;

(7) inspect the construction work area prior to construction for American bittern nests, and if found, proceed in accordance with recommendations from the Massachusetts Natural Heritage Program;

(8) perform construction in environmentally sensitive areas only after consultation with and in accordance with the recommendations of an environmental inspector and wetlands biologist;

(9) install the proposed pipeline at least twenty feet from all residences and other structures normally occupied by humans;

(10) maintain five feet of cover or more over the pipeline in agricultural areas;

(11) implement the mitigation measures recommended by the Massachusetts Historical Commission to minimize disturbance to archaeological areas;

(12) monitor the condition of all roadways impacted by construction for two years and repair any subsequent settling;

(13) repair or reimburse affected property owners for any damage to existing utility, water or sewer lines or pipes caused by construction of the pipeline;

(14) in cooperation with appropriate federal, state and local officials, develop appropriate emergency response plans for possible accidents or related contingencies resulting from operation of the pipeline and meter station facilities, including evacuation procedures and any special provisions warranted by the presence of multiple facilities in the areas between the Knox Road and proposed Bousquet meter stations, and provide a copy of such plans to the Siting Council prior to operation of the pipeline;

(15) publish emergency response plans and procedures in a brochure to be mailed or delivered to all property owners and residents abutting the route, and, if requested, hold public educational forums, prior to operation of the pipeline;

(16) implement the pipeline safety features as presented in the record including: (a) the installation of pipeline warning tape and above-ground markers; (b) the installation of 24-hour flow monitoring and automatic shut-off valve system; and (c) the performance of regular inspections of the pipeline route to detect any leaks and to monitor construction activity by outside parties;

(17) implement the meter station safety features as presented in the record including: (a) utilization of fire-proof and fire-resistant materials and explosion-proof equipment; (b) operation of piping systems below design pressure ratings; (c) installation of gas and fire detection systems; (d) installation of 24-hour monitoring system;

and (e) performance of regular inspections;

(18) establish and maintain tree buffer within the site boundary capable of providing all-season visual screening on all sides of the meter station;

(19) after consultation with appropriate local officials, select a style, material and color for above-ground pipeline markers that is aesthetically acceptable, and provide vegetative screening on all sides of all above-ground valve facilities;

(20) make available for public inspection at Berkshire's offices a plan of the exact location of the pipeline, indicating the depth of the pipeline and showing locations of abutting property lines and existing utility, water and sewer lines;

(21) provide to all property owners and residents abutting the route the phone number of the Mayor's Task Force personnel or other Company designee who will serve as a contact for residents who have concerns regarding pipeline and meter station construction and restoration;

(22) submit a comprehensive report detailing progress or compliance with the conditions set forth in this Decision, on September 30, 1992, December 31, 1992 and March 31, 1993, to the Chairman of the Siting Council, the Siting Council staff, all intervenors and any other interested person.

(23) avoid blasting of ledge at the meter station site to the greatest extent possible by removal of ledge by mechanical means and adjustment of the layout of meter station

structures, consistent with maintaining a tree buffer within the boundary site (see condition 18, above). If Berkshire determines that blasting cannot be avoided, Berkshire shall prepare a report detailing why blasting cannot be avoided by removal of ledge by mechanical means and adjustment of the layout of the meter station structures, prior to conducting any blasting. Berkshire shall submit this report to the Siting Council and shall not conduct any blasting at the meter station site until the Siting Council staff verifies that the report fully satisfies this condition. If blasting is required for construction of the meter station, Berkshire shall notify abutting property owners and residents at least 48 hours prior to conducting any blasting.

The Siting Council 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 with the Siting Council. Therefore, Berkshire must notify the Siting Council of any changes other than minor variations to the proposal so that the Siting Council may decide whether to inquire further into the issue.[144]

The Siting Council further notes that the conditional approval of the pipeline along the primary route and the meter station at the primary site in this proceeding supersedes our

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144/ The petitioner is obligated to provide the Siting Council with sufficient information on changes to enable the Siting Council to make this determination.

conditional approval of the primary pipeline route and meter station site in the 1990 Berkshire Decision (Phase II). However, all other aspects of the 1990 Berkshire Decision (Phase II) will remain in full force and effect.

Robert W. Ritchie

Robert W. Ritchie
Hearing Officer

Jolette A. Westbrook
Hearing Officer

Dated this 26th day of June, 1992

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of June 26, 1992 by the members and designees present and voting. Voting for approval of the Tentative Decision as amended: Gloria Larson, Secretary of Consumer Affairs and Business Regulation; Stephen Remen, Commissioner of Energy Resources; Andrew Greene (for Susan Tierney, Secretary of Environmental Affairs); Tom Black (for Stephen Tocco, Secretary of Economic Affairs); Mindy Lubber (Public Environmental Member); and Kenneth Astill, (Public Engineering member).

Gloria C. Larson

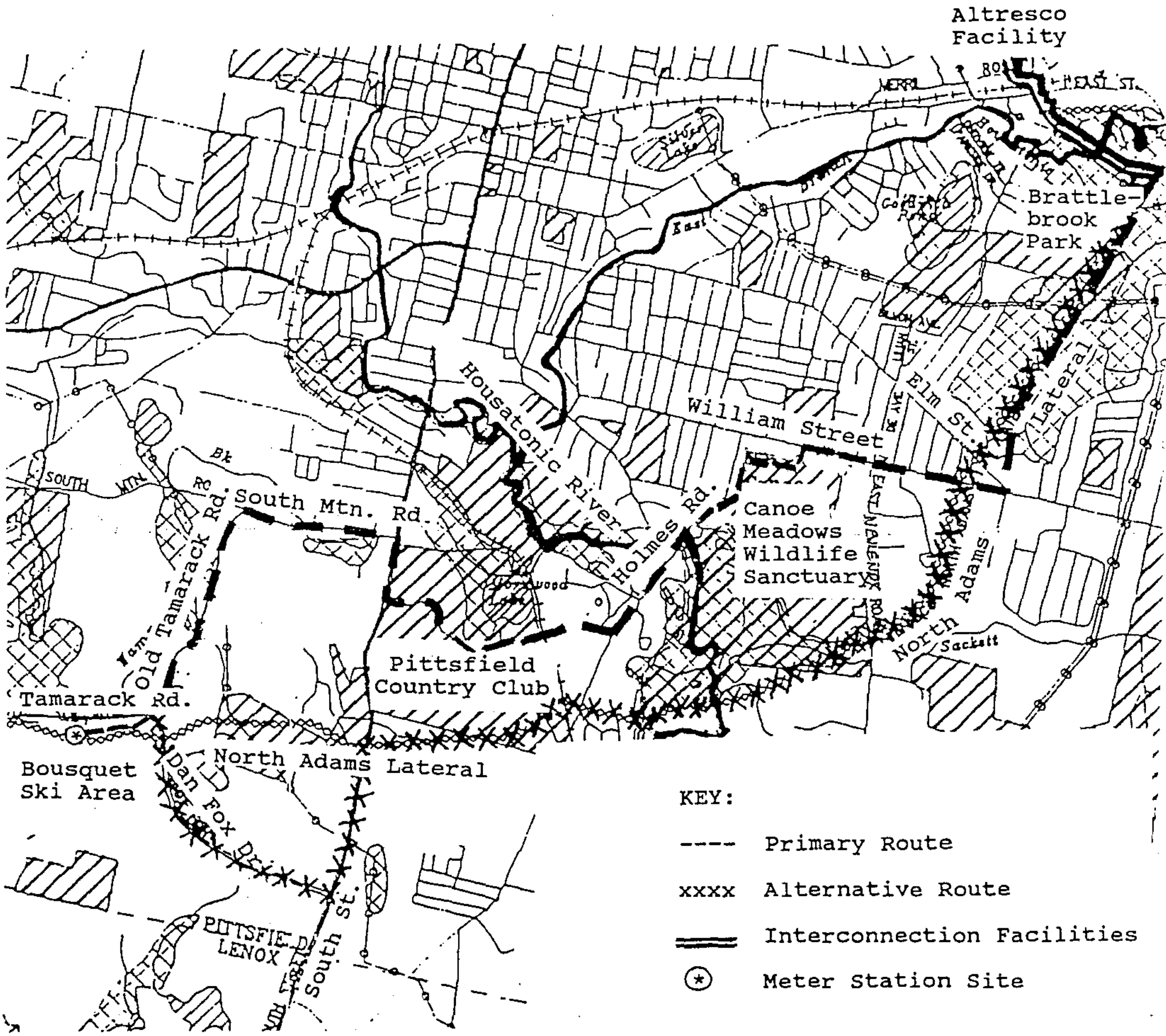
Gloria C. Larson
Chairperson

Dated this 26th day of June, 1992

## FIGURE I

## PRIMARY AND ALTERNATIVE ROUTES

## PRIMARY METER STATION SITE




Source:

Exh. HO-1, Figures 5-2, 5-4

Appeal as to matters of law from any final decision, order or ruling of the Siting Council 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 Council be modified or set aside in whole or in part.

Such petition for appeal shall be filed with the Siting Council within twenty days after the date of service of the decision, order or ruling of the Siting Council, or within such further time as the Siting Council 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).

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

| | | |
|---|---|---|
| In the Matter of the Petition of Boston Gas Company and Massachusetts LNG, Inc. for Approval of the 1991 Forecast of Gas Requirements and Resources | ) | EFSC 91-25 |

FINAL DECISION

Robert W. Ritchie
Hearing Officer
June 26, 1992

On the Decision:

Diedre Matthews

APPEARANCES:

Catherine L. Nesser, Esq.
James Connelly, Esq.
One Beacon Street
Boston, Massachusetts 02108
FOR: Boston Gas Company
Petitioner

John A. DeTore, Esq.
Keohane, DeTore, and Keegan
21 Custom House Street
Boston, Massachusetts 02110
FOR: Distrigas of Massachusetts Corporation
Interested Person

John C. Traficonte, Esq.
200 State Street
Boston, Massachusetts 02109
FOR: Distrigas of Massachusetts Corporation
Interested Person

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The Energy Facilities Siting Council hereby APPROVES the 1991 sendout forecast and supply plan of Boston Gas Company.

## I. INTRODUCTION

### A. Background

Boston Gas Company ("Boston Gas" or "Company") is engaged in the sale and distribution of natural gas to a service area that includes the City of Boston and 73 other cities and towns in eastern Massachusetts (Exh. BGC-1, p. i).[1] In the split year 1990-1991,[2] the Company had an average of 498,573 firm service customers, consisting of 274,762 residential heating customers, 185,749 residential non-heating customers, 35,397 commercial customers, 2,664 industrial customers, and one municipality (id., Tables G-1 through G-3). Boston Gas also makes sales to interruptible and quasi-firm[3] customers (id., Tables G-4(A), revised, and G-4(B), revised).

Boston Gas' forecasts of sendout by customer class are summarized in Table 1. The Company projects an increase of total normalized firm sendout from 79,060 billion Btu ("BBtu")[4] in 1991-92 to 98,281 BBtu in 1995-96, or an increase of

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1/ Based on the thresholds for determining sizes of gas companies within the Commonwealth set forth in the Siting Council's Decision in Evaluation of Standards and Procedures for Reviewing Sendout Forecasts and Supply Plans of Natural Gas Utilities, 14 DOMSC 95 (1986) ("1986 Gas Generic Order"), Boston Gas is considered to be a large-size company.

2/ A split year runs from November 1 through October 31.

3/ The Company defined quasi-firm customers as customers with firm service for less than 365 days per year (Exh. HO-T-9).

4/ For the purposes of this proceeding, one BBtu equals one MMcf, and one MMBtu equals one Mcf.

approximately 24 percent over the forecast period (id., Table G-5).[5]

Boston Gas receives pipeline gas from the Algonquin Gas Transmission Company ("Algonquin") and Tennessee Gas Pipeline Company ("Tennessee"), its two primary pipeline suppliers, as well as Texas Eastern Transmission Company ("TETCO") (id., pp. 44, 51-52). Boston Gas also purchases gas directly from the Boundary Gas consortium (id., pp. 52-53). Further, the Company has access to storage services provided by Tennessee and Algonquin (Exh. BGC-1, pp. 54-59).[6] Boston Gas has auxiliary liquefied natural gas ("LNG") facilities in Dorchester (Commercial Point facility), Lynn, and Salem; auxiliary propane facilities in Everett and ten satellite locations; and a synthetic natural gas production facility in Everett (id., pp. 62-65). Additionally, Boston Gas has contracted with Distrigas of Massachusetts Corporation ("DOMAC") for the use of LNG storage and vaporization facilities and with Algonquin for the use of LNG storage facilities (id., pp. 60-62).

In its most recent decision regarding Boston Gas, the Energy Facilities Siting Council ("Siting Council" or "EFSC") approved the Company's sendout forecast and supply plan for the five year period from 1988-89 through 1992-93. Boston Gas Company, 19 DOMSC 332 (1990) ("1990 Boston Gas Decision"). In addition, the Siting Council required the Company to comply with 14 orders contained in that decision. 1990 Boston Gas Decision, 19 DOMSC at 463-466.

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5/ The Company indicated that actual total firm company sendout was 66,586.5 BBtu in 1990-91, and that normalized firm sendout for that year was 73,065 BBtu (Exh. BGC-1, Table G-5).

6/ Boston Gas sends gas to underground storage during the non-heating season and the gas is returned for sendout during the heating season (Exh. BGC-1, p. 54).

B. Procedural History

On July 1, 1991, Boston Gas and Massachusetts LNG, Inc. ("Mass LNG") filed a petition for approval of their forecast and supply plan for the split years 1991-92 through 1995-96.[7] On July 11, 1991, the Siting Council entered into a Memorandum of Understanding ("MOU") with the Massachusetts Department of Public Utilities ("DPU" or "the Department") providing for cooperation between the two agencies with respect to this proceeding and the Company's petition filed with the DPU pursuant to G.L. c. 164, §94A, for approval of its gas sales agreement with Alberta Northeast Gas Limited ("ANE").[8] The MOU also provides that each agency: (1) incorporate into its record the record developed in the other agency's proceeding; (2) give due consideration to the legal conclusions developed in the other agency's proceeding; and (3) agree to rely on the findings developed in the other agency's proceeding, as appropriate. Pursuant to the MOU, the EFSC also agreed to incorporate in this proceeding the record of DPU 90-320, which addresses (1) the Company's preapproval filing for its commercial and industrial demand-side management ("DSM")[9] programs and (2) the Company's DSM monitoring and evaluation plan.[10]

On August 2, 1991, the Hearing Officers of the two agencies issued a joint Notice of Adjudication and directed the

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7/ In December 1973, Boston Gas acquired all outstanding stock of Mass LNG (Exh. BGC-1, p. i). Mass LNG leases two LNG storage and vaporization facilities located in Lynn and Salem to Boston Gas on a long-term basis (id., pp. i, 62-63). Mass LNG makes no wholesale or retail sales of gas (id., p. i). The Siting Council's discussion of LNG facilities will refer to Boston Gas but apply to Mass LNG where appropriate.

8/ The DPU proceeding has been docketed as DPU 91-156.

9/ For the purposes of this decision, DSM refers to the Company's conservation and load management ("C&LM") initiatives.

10/ Pursuant to the MOU, both the records in DPU 91-156 and DPU 90-320 are incorporated into this record.

Company to publish and post the Notice in accordance with 980 CMR 1.03(2). The Company confirmed notice and publication on September 9, 1991. On September 23, 1991, DOMAC petitioned to participate as an interested person. On September 24, 1991, the Siting Council granted DOMAC's request to participate.

The Siting Council conducted seven days of evidentiary hearings during the proceeding, two of which were conducted jointly with the DPU regarding the ANE supply.[11] Boston Gas presented six witnesses: Susan M. Houghton-Fenton ("Ms. Fenton"), Director of Business Forecasting and Market Research at Boston Gas, who testified regarding the Company's traditional and non-traditional demand forecasts, and the decision to purchase the ANE supply; Amy Smith, gas supply analyst at Boston Gas, who testified regarding the Company's sendout forecast, including weather data, and the regression analysis; Christopher Gulick, the Company's manager of gas-supply planning and acquisition, who testified regarding planning standards, the large-scale cogeneration forecast, gas supply planning, supply adequacy, and the decision to purchase the ANE supply; Jennifer L. Miller, General Counsel of Boston Gas and chair of the Company's integrated resource management task force, who testified regarding the Company's supply planning process, its DSM programs, and the decision to pursue the ANE volumes; Susan L. Fleck, superintendent of distribution administration for Boston Gas, who testified regarding distribution system planning; and Beth Greenblatt, director of DSM for the Company, who testified regarding DSM programs.

The Hearing Officer entered 245 exhibits into the record, including 16 DPU exhibits, largely composed of responses to information and record requests. Boston Gas entered 14 exhibits

11/ On March 18, 1992, the DPU held an additional supplemental hearing on the ANE supply, in which Siting Council staff participated.

into the record. On April 3, 1992, the Company filed its brief.[12] On June 23, 1992, Boston Gas submitted a motion to reopen the record. In a Procedural Order dated June 25, 1991, this motion was denied.

12/ The Company filed a revised brief, correcting minor typographical errors, on April 10, 1992.

## II. ANALYSIS OF THE SENDOUT FORECAST

### A. Standard of Review

The Siting Council is directed by G.L. c. 164, § 69I, to review the sendout forecast of each gas utility to ensure that the forecast accurately projects the gas sendout requirements of the utility's market area. The Siting Council's regulations require that the forecast exhibit accurate and complete historical data and reasonable statistical projection methods. See 980 CMR 7.02(9)(b). A forecast that is based on accurate and complete historical data, as well as reasonable statistical projection methods, should provide a sound basis for resource planning decisions. Colonial Gas Company, 23 DOMSC 351, at 358 (1991) ("1991 Colonial Decision"); Boston Gas Company, 19 DOMSC 332, 340 (1990) ("1990 Boston Gas Decision"); Bay State Gas Company, 19 DOMSC 140, 145 (1989) ("1989 Bay State Decision"); Fitchburg Gas and Electric Company, 19 DOMSC 69, 73 (1989) ("1989 Fitchburg Decision"); Berkshire Gas Company, 16 DOMSC 53, at 56 (1987) ("1987 Berkshire Decision").

In its review of a forecast, the Siting Council determines if a projection method is reasonable based on whether the methodology is (a) reviewable, that is, contains enough information to allow a full understanding of the forecast methodology; (b) appropriate, that is, technically suitable to the size and nature of the particular gas company; and (c) reliable, that is, provides a measure of confidence that the gas company's assumptions, judgments, and data will forecast what is most likely to occur. 1991 Colonial Decision, 23 DOMSC at 358; 1990 Boston Gas Decision, 19 DOMSC at 340; 1989 Bay State Decision, 19 DOMSC at 145; 1989 Fitchburg Decision, 19 DOMSC at 73; 1987 Berkshire Decision, 16 DOMSC at 55-56.

B. Previous Sendout Forecast Review

In the 1990 Boston Gas Decision, the Siting Council approved Boston Gas' sendout forecast, which included both a forecast of demand in traditional end use markets and forecasts of demand in the new markets of small-scale cogeneration, gas air conditioning, and large-scale cogeneration (19 DOMSC at 360). In that decision, the Siting Council expressed concerns about the Company's weather data and planning standards. Id., at 357-358. The Siting Council also indicated that the Company needed to improve its forecasting methods for the new, non-traditional markets. Id. at 372-374. As a result of these concerns, the Company was ordered to:

> (1) include a detailed study of temperatures across its service territory covering all seasons and identifying the typical range of temperatures across the service territory, as well as the average temperatures in relation to temperatures at Logan Airport for the same dates. The results of this study shall be used to either justify continued use of Logan DD data for the entire service territory or as the basis of a decision to use a new source or additional sources of weather data (Order One);
>
> (2) provide a comprehensive analysis identifying the appropriate level of reliability for design year planning based on the Company's sendout mix, resource mix, and distribution system, in addition to an analysis of the cost impacts of such reliability (Order Two);
>
> (3) provide a comprehensive analysis identifying the appropriate level of reliability for design day planning based on the Company's sendout mix, supply mix (accounting for supply reserve margins and standby capacities as appropriate), and distribution system, in addition to an analysis of the cost impacts of such reliability, including capacity and distribution upgrade costs as appropriate (Order Three);
>
> (4) include territory specific studies designed to develop a reliable database of building types, energy use, and market potential for traditional cogeneration development (Order Four);
>
> (5) provide a detailed methodology for forecasting load additions in the large, non-traditional cogeneration market including a specific analysis of market potential,

market growth targets, and marketing programs to achieve such growth targets (Order Five). Id., at 463-364.

Boston Gas's compliance with Order One is discussed in Section II.C.1.b, below; Boston Gas's compliance with Order Two is discussed in Section II.C.3.b, below; Boston Gas's compliance with Order Three is discussed in Section II.C.4.b, below; Boston Gas's compliance with Order Four is discussed in Section II.D.2.a.ii, below; and Boston Gas's compliance with Order Five is discussed in Section II.D.2.f.ii, below.

C. Planning Standards

In accordance with its statutory mandate to ensure a reliable energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost, the Siting Council is required to review long-range forecasts of gas companies (see G.L. c. 164, § 69H, 69I, and 69J).

The first element of the Siting Council's review of planning standards is its review of a company's weather data. The accuracy of weather data is important because weather data is the basic input from which a company's planning standards are developed. The second element of the Council's review is an analysis of the planning standards themselves -- how the company arrived at its normal year, design year, and design day standards. A company's standards are used as the basis for projecting its sendout forecasts which, in turn, are used for ascertaining the adequacy and cost of a company's supply plan. The Siting Council therefore reviews a company's planning standards to ensure that they are reviewable, appropriate, and reliable.

1. Weather Data

a. Description

In its last decision, the Siting Council found that Boston Gas developed its planning standards using a weather database which was reviewable, and minimally appropriate and reliable. 1990 Boston Gas Decision, 19 DOMSC at 348. In addition, the Siting Council directed the Company to monitor the correlation between sendout, degree days ("DD") and effective degree days ("EDD"), and ordered it to provide a study of temperatures across its service territory. Id., at 346-348.

In the current proceeding, Boston Gas indicated that it used a DD database spanning the years 1920 to 1985 to evaluate its planning standards (Exh. BGC-1, p. 22). The Company indicated that it chose not to include data from 1986-1990 in this evaluation, even though it had collected these data (id.). The Company stated that annual degree days in Boston follow a 20-to-21 year cycle, with the 1920 to 1985 database containing three such cycles, and expressed the concern that adding the 1986-1990 data might create a database skewed by the inclusion of a partial cycle (id.). The Company provided two studies describing weather cycles and two graphs showing weather patterns from 1920 to 1990 to document its assertion that annual degree days are cyclical in nature (id., Charts I-B-2 and I-B-3, Exh. HO-WD-1). It also provided comparisons of the probability of occurrence of various design standards using a 1920 to 1985 database, and a 1920 to 1990 database[13] (Exhs. HO-DS-1, HO-DS-13).

The Company's witness, Amy Smith, indicated that the Company was unsure whether the cyclical pattern in Boston weather would continue, and stated that, until the Company had made this determination, it would be unwilling to use data more recent than

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13/ Use of the updated database changed the probability of occurrence of a 6000 DD year from 17.9 percent to 17.6 percent, and the probability of occurrence of a 6100 DD year from 11.1 percent to 10.9 percent. The probabilities of 6200, 6300 and 6400 DD years did not change. Use of the updated database changed the probability of occurrence of a 68 DD day from 5.3 percent to 5.1 percent. The probabilities of 73, 78, and 83 DD days did not change.

1985 for planning purposes (Tr. 3, pp. 22-23). Ms. Smith stated that she did not know how many years it would be before the Company could determine whether the cyclical pattern was continuing (id., p. 24).

In response to the previous Siting Council decision, Boston Gas presented a study of the use of EDD for long-range modelling (Exh. BGC-1, p. 23). The study compared the effectiveness of the Company's traditional database of DD data collected at Logan airport ("Logan DD"), DD data collected by Weather Services Corporation ("WSC") at Logan ("WSC DD"), and EDD data collected by WSC at Logan ("WSC EDD") in predicting sendout over the period from November 1989 to October 1990 (id.). The Company stated that Logan DD are the average of minimum and maximum temperatures over the 24-hour period from midnight to midnight, while the weather data provided by WSC are the averages of observations taken every three hours from 8 a.m. to 8 a.m. (id.).[14] The Company noted that WSC DD are a better predictor of sendout than are Logan DD, and that WSC EDD are better still.[15] Ms. Smith indicated that the improvement seen when WSC degree days were used could be attributed primarily to more frequent temperature readings and measurement over a period which corresponds to the Company's business day (Tr. 3, p. 30). She

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14/ Ms. Smith noted that Boston Gas measures daily sendout from 8 a.m. to 8 a.m.

15/ The use of Logan DD in the Company's regression analysis of the previous year's sendout resulted in an R-squared value of .9896; the equation using WSC DD had an R-squared value of .9950, while the equation using WSC EDD had an R-squared value of .9954 (Exh. BGC-1, p. 24). R-squared is a measure of the amount of variation in the dependent variable which is explained by the variation in the independent variables. R-squared values range between 0.00 and 1.00, where 0.00 indicates no variation explained by the independent variables, and where 1.00 indicates complete explanation by the independent variables. The Company stated that it performed tests which indicate that these differences in the R-squared value are significant (id.).

indicated that the additional improvement seen when WSC EDD were used could be attributed to the inclusion of wind factors (id.).

Boston Gas stated that, as a result of this study, it has decided to acquire 20 years of historical DD and EDD data from WSC, and to use the new EDD data in its next filing with the Siting Council (Exhs. HO-WD-4, HO-WD-9). However, the Company stated that, "while EDD may be a better tool than DD for long-range forecasting, the use of DD data does not compromise the accuracy of the 1991 Forecast" (Exh. BGC-1, p. 23).

Finally, in response to Order One of the previous decision, the Company presented a study comparing the daily temperatures over 20 years at National Oceanic and Atmospheric Administration ("NOAA") weather stations in and near its service territory with the temperatures reported at Logan International Airport (id., p. 25).[16] The Company performed statistical tests to determine the degree to which daily minimum, maximum, and average temperatures at each of these weather stations were linearly related to minimum, maximum and average temperatures at Logan (id., p. 26). The Company also presented a series of regressions to determine the relationship between Logan temperatures and the temperatures at other weather stations (id., p. 27.) The Company asserted that these analyses indicate a high degree of linear correlation between the Logan weather station and the ten other weather stations examined in the study (id., p. 28).[17] The Company indicated that it concluded from

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16/ These weather stations were: Bedford, Milton, Brockton, Haverhill, Lowell, Marblehead, Reading, Southbridge, West Medway, and Worcester.

17/ The average temperature correlation coefficients for those stations with complete information available ranged from .910 to .996 (Exh. BGC-1, Chart I-B-10, page 3). Perfect linear correlation would result in a coefficient of 1.0. R-squared values of the average temperature regressions for those stations with complete information available ranged from .9665 to .9854 (id., Chart I-B-22). Perfect linear correlation would result in an R-squared value of 1.0.

this study that it can accurately forecast sendout using only the Logan weather data (id., pp. 28-29). The Company also noted that 69 percent of its demand comes from portions of its territory which are closer to Logan than to any other weather station (id., p. 25; Exh. HO-WD-5).

b. Analysis and Compliance with Order One

In Order One of the 1990 Boston Gas Decision, the Siting Council ordered Boston Gas to:

> (1) include a detailed study of temperatures across its service territory covering all seasons and identifying the typical range of temperatures across the service territory, as well as the average temperatures in relation to temperatures at Logan Airport for the same dates. The results of this study shall be used to either justify continued use of Logan DD data for the entire service territory or as the basis of a decision to use a new source or additional sources of weather data (19 DOMSC at 463).

Here, Boston Gas has presented an extensive analysis demonstrating that minimum, maximum, and average DD patterns throughout its territory are strongly correlated with the weather recorded at Logan Airport. The Company argued that, since the weather at any point in its service territory can be expressed as a linear transformation of Logan weather, there is no benefit to be gained from incorporating additional sources of weather data into its planning process.

The Siting Council notes that the Company's argument assumes that sendout is a linear function of DD, while some of the variables used by the Company to forecast sendout, such as the cold snap factor, are not strictly linear.[18] However, since the impact of these non-linear variables is quite small, it is

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18/ The cold snap factor increases the sendout forecast by 4 percent on days of 40 DD or higher (See Section II.D.4, below) (Exh. BGC-1, p. 31).

reasonable for the Company to use this study to justify continued use of the Logan airport data (see Section II.D.3, below, for a discussion of the regression equation). Consequently, the Siting Council finds that the Company has complied with Order One of the previous decision.

In its previous decision, the Siting Council approved the use of standard DD data for use in long-range modelling, but noted a consistent, though minor, improvement when EDD were used, and directed the Company to continue to monitor the effectiveness of EDD. 1990 Boston Gas Decision, 19 DOMSC at 346. Here, the Company has presented a study demonstrating that, over a recent time period, EDD remain more effective than DD in predicting sendout. The Company has also determined that data collected by its weather service vendor, WSC, is a more effective predictor of sendout than is the average DD data traditionally used by the Company. Based on this study, the Company has decided to acquire both standard and EDD data from WSC; it will use the EDD data in its next filing, and will continue to monitor the relative value of standard and EDD data.

The Company has attempted to seek out more effective weather data for use in its long-range modelling. Based on the evidence presented in this proceeding, the WSC EDD data have proven to be an extremely effective predictor of territory-wide sendout. As long as the Company has no operational problems delivering gas to specific parts of its territory, the WSC EDD data should be an appropriate and reliable weather database for planning purposes. The Siting Council encourages the Company to continue to monitor the results of the two data sets which it will be receiving from WSC. Further, the Siting Council agrees with the Company that, although EDD data affords some improvement in long-range modelling, the use of its DD data does not invalidate the forecast under review.

However, the Siting Council is concerned with the period of time covered by the Company's weather database. In previous decisions, the Siting Council has clearly stated that gas companies must use up-to-date weather data as the basis for their planning process, and has ordered companies which have not complied to do so. 1989 Fitchburg Decision, 18 DOMSC at 78-79; 1988 Commonwealth Decision, 17 DOMSC at 81; 1987 Boston Gas Decision, 16 DOMSC at 187. Here, the Company has chosen not to use up-to-date weather data, stating that the cyclical nature of New England weather makes the use of the post-1985 data inappropriate.

Boston Gas has presented evidence which suggests that the number of annual degree days in New England may follow a cyclical pattern. The Company has also stated that it is not certain whether this historical pattern will continue. The Siting Council notes that, if the Company expects the cyclical pattern to continue, it should use a 1925 to 1990 weather data base, thus eliminating partial cycles while including current weather data. If the Company does not expect the cyclical pattern to continue, it should use a 1920 to 1990 weather data base, which would include three full cycles (1920-1985) plus additional, non-cyclical, data (1986-1990). If it is not sure whether the cyclical pattern will continue, it should compare the results of the 1925-1990 database with those of the 1920-1990 database, to determine whether the Company's uncertainty should be reflected in its planning. Under none of these circumstances is the 1920-1985 database used by the Company appropriate.

Nevertheless, Boston Gas has presented the Siting Council with a comparison of the probabilities of occurrence of various design days and years using the 1920-1985 database and the 1920-1990 database.[19] This comparison indicates that the use of an

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19/ In its evaluation of its planning standards, the Company weighed the costs of planning for a variety of design days and years against the probability that these days and years would occur. These probabilities were determined through an analysis of the historical weather database. A more detailed discussion of the Company's evaluation of its planning standards updated database does not significantly affect these probabilities. The Siting Council therefore finds that the use of outdated weather data has not compromised the reliability of this forecast. The Siting Council has also found that the Company has complied with Order One of the previous decision.

Based on the above, the Siting Council finds that the weather database used by the Company in this filing is reviewable, minimally appropriate, and reliable. However, in order for the Siting Council to approve the Company's planning standards in its next forecast filing, the Company must base its planning standards on an up-to-date weather database.

2. Normal Year Standard

Boston Gas stated that it used a normal year standard of 5695 DD to develop its sendout forecast (Exh. BGC-1, p. 33). The Company indicated that this standard was developed in 1988, and represents the average calendar year degree days for the years 1920-1985 (id.). In the 1990 Boston Gas Decision, the Siting Council found that the Company's methodology for determining its normal year standard was reviewable and appropriate (19 DOMSC at 13). The Siting Council has also found that the use of the 1920-1985 weather database in developing planning standards has not compromised the reliability of this forecast (see Section II.C.1.b, above). Consequently, the Siting Council finds that the Company's normal year standard is reviewable, appropriate, and reliable.

3. Design Year Standard

In its 1986 Gas Generic Order, the Siting Council notified gas companies that renewed emphasis would be placed on design criteria "to ensure that those criteria bear a reasonable relationship to design conditions that are likely to be

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is found in Sections II.C.3 and II.C.4, below.

encountered" (14 DOMSC at 97). The Siting Council ordered each company, in each forecast filing, to include a detailed discussion of how and why it selected the design weather criteria that it uses, giving particular attention to the frequency with which design conditions are expected to occur, and to the effect of the design standard on the reliability of the company's forecast and the cost of its supply plan. Id., at 96-97, 104-105. Further, in past decisions, the Siting Council has stated that the largest gas companies in Massachusetts must consider tradeoffs between reliability and cost in establishing design standards. 1990 Boston Gas Decision, 19 DOMSC at 349; 1989 Bay State Decision, 19 DOMSC at 154; 1988 ComGas Decision, 17 DOMSC at 87; 1987 Boston Gas Decision, 16 DOMSC at 188-190.

In its previous decision, the Siting Council expressed its concern that the Company had failed to establish an appropriate level of design year reliability based on the particulars of the Company's capacity and supply portfolios, and ordered the Company to provide an analysis of this issue in the current filing. 1990 Boston Gas Decision, 19 DOMSC at 353.

a. Description

Boston Gas stated that its design year standards, which were set in 1988 based on a 1920-1985 weather database, are: 6300 DD in a design year, 4962 DD in a five-month design winter, and 3381 DD in the December to February period (Exh. BGC-1, p. 33).

In response to the Siting Council's order in the 1990 Boston Gas Decision, the Company provided an analysis of the appropriate balance of cost and reliability in a design year standard (id., pp. 33-34). The Company stated that it approached this question by comparing the cost of maintaining service at specific design year levels[20] with the cost associated with

20/ The Company evaluated the costs of maintaining supplies to meet design years of 6000 DD, 6100 DD, 6200 DD, 6300 DD, 6400 DD, and 6500 DD in the year 1995 (Exh. BGC-1, weather exceeding the design year standard (id., p. 34). The Company stated that it assumed that the incremental supplies needed to maintain service would be seasonal supplies, which the Company modeled as underground storage filled with spot gas and returned under interruptible transportation (id., p. 37).

The Company indicated that it estimated the cost of weather exceeding the design year standard by taking the costs it incurred to secure additional gas during the winter of 1980-1981,[21] and inflating them by 5 percent annually (id., p. 37). The Company stated that it added to this the costs of a 1 percent loss of load growth each year for five years (id.).[22] The Company estimated that this cost of not meeting a design year standard was approximately $95 million (id., Chart I-B-33, page 1). To test the sensitivity of this analysis to cost levels, the Company analyzed costs of $75 million, $100 million, $125 million, and $150 million (id.).[23,24] These costs were

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p. 37).

21/ Boston Gas stated that the winter of 1980-81 was a period of extremely cold weather which resulted in a severe shortage of natural gas in the Northeast (Exh. BGC-1, p. 37; Tr. 3, pp. 74-75). The Company provided a list of suppliers from whom it made emergency purchases during the shortage (Exh. HO-DS-9, supplement).

22/ The Company's witness, Christopher Gulick, indicated that he had made a study of the impact of gas curtailments in the late 1970s on gas company load growth, and believed that a 1 percent loss of load growth each year over five years was a realistic assessment of that impact (Tr. 3, pp. 81-82).

23/ The Company later updated these costs to correct an arithmetic error (Exh. HO-DS-6). It submitted a revised cost estimate of $103 million, and an analysis of costs of $83 million, $108 million, $133 million, and $158 million (id.).

24/ Mr. Gulick indicated that he chose to evaluate a larger number of costs higher than the point estimate because he believed the costs of acquiring additional gas were more likely to exceed the estimate than fall short of it (Tr. 3, pp. 79-80).

multiplied by the probability of occurrence of each of the design years, to determine a probability-weighted cost of weather exceeding the design year standard for each design year (id., pp. 37-38). The Company presented a graph showing the intersections of the cost of storage with the four estimates of the cost of weather exceeding the design year standard, and stated that the analysis indicates that the existing design year standard achieves an appropriate balance between reliability and cost (id., p. 34, Chart I-B-33, page 1).[25]

Mr. Gulick indicated that he believed the Company's 1980-81 experience was an appropriate proxy for a future gas shortfall, since the capacity which the region has acquired since the early 1980s has been balanced by regional load growth (Tr. 3, pp. 75-77). Mr. Gulick also indicated that the cost of gas to fill the storage areas had not been included in the costs of planning to meet design standards (id., p. 73). He noted, however, that these costs, unlike the reservation costs for the storage, would not be borne by customers unless design conditions actually occurred (id.).

b. Analysis and Compliance with Order Two

In Order Two of the 1990 Boston Gas Decision, the Siting Council ordered Boston Gas to:

> provide a comprehensive analysis identifying the appropriate level of reliability for design year planning based on the Company's sendout mix, resource mix, and distribution system, in addition to an analysis of the cost impacts of such reliability (19 DOMSC at 463).

In responding to this order, the Company has presented a classic cost-benefit analysis of the appropriate level of reliability for design year planning. The Company's analysis

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25/ An inspection of this chart indicates that the optimal design year standard varies between approximately 6230 DD and approximately 6320 DD, depending on the assumed costs due to exceeding the design year (Exh. BGC-1, Chart I-B-33, page 1).

assumed that the costs of reliability are the gas costs incurred by the Company in planning for a particular design year. The benefits of reliability were modelled as the avoided costs of buying gas at premium prices to meet customer needs if the winter is colder than planned for by the Company. These avoided costs are multiplied by the probability of colder-than-design weather, to account for the fact that they will be incurred only in colder-than-design weather. The Siting Council notes that this model is substantially more sophisticated than any previous analysis of gas company design standards presented by a company for review by the Siting Council.

The reliability of a cost-benefit analysis depends on the appropriateness of the cost and benefit assumptions used. Here, the Company has based its costs on current prices for storage service, escalated to 1995. The Siting Council recognizes that, in design year planning, it is appropriate for the Company to analyze its need for seasonal supplies, rather than capacity. The Siting Council notes that Boston Gas intends to acquire storage services to meet seasonal needs within the forecast period. Therefore, we conclude that the Company's assessment of the costs of the various levels of reliability is appropriate and reliable.

The Siting Council notes, however, two concerns regarding the Company's derivation of the benefits of reliability. First, Boston Gas has modelled the costs of a sizable supply shortfall requiring numerous emergency purchases from multiple suppliers over a two-month period. However, the Company in its calculations has used the probability of weather which meets the design year, not of weather which exceeds it by enough to create a sizable shortfall. Second, the Company added to the gas costs an estimate of lost revenue over five years; the Siting Council notes that lost revenue will affect the Company's shareholders, while the other costs and benefits of reliability will accrue to gas customers.

However, the Company's analysis compensates somewhat for these concerns, and for the more general uncertainty underlying any calculation of future benefits, by evaluating the sensitivity of its analysis to a wide range of estimated benefits. The Company's analysis indicates that, over this range, the preferred design year standard clusters around the Company's current standard of 6300 DD.[26] Thus, the Company's analysis supports the choice of a design year standard of 6300 DD as reflecting an appropriate tradeoff between cost and reliability. Consequently, the Siting Council finds that the Company's design year standard is reviewable, appropriate and reliable. The Siting Council notes that the Company will be developing a new design year standard based on the WSC EDD weather database, and expects that the Company will use a refined version of this model, or a similar analysis of the tradeoff between cost and reliability, in its development of a new standard.

Finally, while the Company has presented an adequate cost-benefit analysis to support its design year standard, the Siting Council notes that Order Two required Boston Gas to consider the Company's sendout mix, resource mix, and distribution system, as well as the cost impacts of reliability, in developing its design year standard. The Company has not specifically addressed these issues in its analysis. Consequently, the Siting Council finds that the Company has only partially complied with Order Two of the 1990 Boston Gas Decision. The Siting Council encourages Boston Gas to give specific consideration to these issues as it develops its new design year standard.

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26/ The Siting Council notes that the Company evaluated benefits ranging from $75 million to $150 million, when the Company's estimate was $95 million. The sensitivity analysis would carry more weight if the range of benefits evaluated were more symmetric.

4. Design Day Standard

The Siting Council's decision in the 1986 Gas Generic Order regarding the development of design criteria applies both to design year and design day standards (14 DOMSC at 97). Likewise, the Siting Council's directive to gas companies regarding the need to consider tradeoffs between reliability and cost in establishing design standards must be applied to both design year and design day standards.

In the 1990 Boston Gas Decision, the Siting Council expressed concern that the Company, which had provided an extensive analysis of the cost of peak day capacity, had not addressed peak day reliability with equal sophistication (19 DOMSC at 357-358). The Siting Council therefore ordered the Company to analyze the appropriate level of reliability based on the Company's sendout mix, supply mix, and distribution system. Id.

a. Description

The Company stated that it used a design day of 73 DD, based on an actual 73 DD which occurred on February 9, 1934 (Exh. BGC-1, p. 33). The Company indicated that it evaluated the reasonableness of this standard by comparing the costs of capacity to maintain various design day standards[27] with the costs to the Company and its customers should a loss of service occur as a result of a design day capacity shortage (id., p. 35.)

The Company indicated that it used the cost of firm storage return from upstate New York to model the capacity costs of maintaining different design day capacities (Exh. HO-DS-2). Mr. Gulick stated that firm transportation from storage was not currently Boston Gas's marginal supply on peak days, nor was it the supply which the Company would currently acquire if it

27/ The Company evaluated the costs of planning for design day standards of 68 DD, 73 DD, 78 DD and 83 DD (Exh. BGC-1, Chart I-B-3, page 2).

increased its design day standard; rather, it represented "the next likely increment that we would seriously consider investing in in order to meet sendout requirements" (Tr. 3, pp. 34, 38).[28] The Company also included the costs of facility replacements required to meet design standards (Exh. HO-DS-7).

The Company identified three types of costs which would result from a loss of service: the costs of shutting off and restarting service to customers; customer losses due to repairs, alternate shelter, business closings, and the like made necessary by the loss of service; and lost revenue from slower Company growth (Exh. BGC-1, pp. 35-36). The Company modelled shutdown and restart costs for 65,000 and 125,000 customers using insurance studies for plant losses at Commercial Point and Everett (Exh. HO-DS-4). The Company estimated damages resulting from the shutdowns at $2500 to $10,000 per customer (Exh. BGC-1, p. 36). The Company indicated that these estimates were "reasonable assumptions" (Exh. HO-DS-5). The Company also calculated the lost revenues which would result from a 0.5 percent and 1 percent loss of growth over 5 years (Exh. BGC-1, p. 36). The Company indicated that it calculated low and high estimates of the cost of loss of service at $170.8 million and $1266.6 million, respectively; it then increased the range to $85.4 million to $1.9 billion to allow for further uncertainty (id., p. 36 and Chart I-B-31, p. 1). The Company stated that it multiplied these costs by the probability of occurrence of each of the design day levels, to determine a probability-weighted cost of weather exceeding the design day standard for each design day (id., p. 36). The Company stated that its analysis indicated

28/ At the Siting Council's request, the Company also provided an analysis which used propane to model capacity costs; however, the Company noted that it was moving away from propane as a peaking supply, and would be unlikely to acquire it in the future (Exh. HO-DS-3).

that its design day standard should lie between 71 and 76 DD (id., p. 36).

Mr. Gulick stated that the Company would not actually shut off large numbers of customers if the design day were exceeded by only a few degree days; instead, it would bring on standby capacity and attempt to get additional pipeline gas (Tr. 3, pp. 68-69). He indicated that customer disturbance would increase if the design standard were exceeded by a larger amount (id., p. 69-70). He also noted that the chances of weather exceeding the design standard by a large amount would be higher if the standard itself were lower (id., p. 70).

b. Analysis and Compliance with Order Three

In Order Three of the 1990 Boston Gas Decision, the Siting Council ordered the Company to

> provide a comprehensive analysis identifying the appropriate level of reliability for design day planning based on the Company's sendout mix, supply mix (accounting for supply reserve margins and standby capacities as appropriate), and distribution system, in addition to an analysis of the cost impacts of such reliability, including capacity and distribution upgrade costs as appropriate (19 DOMSC at 463).

Here, the Company has presented a cost/benefit analysis similar to its design year analysis. Again, the Company has developed a relatively sophisticated approach to analyzing design standards. However, the Siting Council has serious concerns about the reliability of the cost assumptions used in this analysis.

In calculating the cost of capacity to ensure peak day reliability, the Company used the costs of its next planned capacity addition, firm transportation from storage in upstate New York. However, the Company intends to acquire this storage primarily to meet seasonal requirements; while the storage would provide peak day capacity, it does not necessarily represent a least-cost approach to achieving a specific level of peak day reliability. For the purposes of this review, the Siting Council accepts firm transportation from storage as a reasonable proxy for the cost of reliability. However, the Siting Council expects the Company to consider alternative capacity additions in its next analysis.

Further, in calculating the benefits of reliability, the Company estimated the avoided costs of shutting off service to customers. However, Mr. Gulick has testified that the Company would not shut off customers on this scale if the design day were exceeded by only a few degree days. While the Company has evaluated its design day standard over a broad range of reliability benefits, that range is based on the premise that weather exceeding the design day standard would lead to a large-scale loss of service. This is not necessarily the case. A more robust analysis of the benefits of reliability would consider both the costs of exceeding design day by a few degree days and the costs of exceeding it by a margin which would lead to large-scale loss of service.

The Siting Council is particularly concerned about this analysis of reliability benefits because the probability of substantially exceeding a design day is much lower than the probability of that day's occurrence, yet the Company used the probability of design day occurrence to estimate the likelihood of a loss of service. This may have led the analysis to overstate the appropriate range for the design day standard.

Nonetheless, for the purposes of this review, and recognizing that Boston Gas has developed a relatively detailed level of analysis for design standards, the Siting Council finds that the Company's design day standard is reviewable, appropriate, and minimally reliable. The Siting Council notes that the Company will be developing a new design day standard based on the WSC EDD weather database, and expects that the Company will use a refined version of this model, or a similar analysis of the tradeoff between cost and reliability, for this purpose.

Finally, while the Company has presented an adequate cost-benefit analysis to support its design year standard, the Siting Council notes that Order Three required Boston Gas to consider the Company's sendout mix, resource mix, and distribution system, as well as the cost impacts of reliability, in developing its design day standard. The Company has not specifically addressed these issues in its analysis. Consequently, the Siting Council finds that the Company has only partially complied with Order Three of the 1990 Boston Gas Decision. The Siting Council encourages Boston Gas to give specific consideration to these issues as it develops its new design day standard.

5. Conclusions on Planning Standards

The Siting Council has found that: (1) the Company has a reviewable, minimally appropriate and reliable weather database for use in the development of its planning standards; (2) the Company has a reviewable, appropriate, and reliable normal year standard; (3) the Company has a reviewable, appropriate, and reliable design year standard, and (4) the Company has a reviewable, appropriate, and minimally reliable design day standard.

Accordingly, for the purposes of this proceeding, the Siting Council finds that, on balance, the Company's planning standards are reviewable, appropriate, and reliable.

D. Forecast Methodologies

The filing currently under review is the third in which Boston Gas has presented a demand-based sendout forecast. In its 1986 filing, the Company presented a sendout forecast based on an interim end use demand model, which projected load growth in the residential, apartment, and commercial/industrial sectors, and a regression analysis of existing sendout. 1987 Boston Gas

Decision, 16 DOMSC at 192. In its 1988 filing, the Company presented a forecast based on a completed traditional end use demand model, separate forecasts of gas-fired air conditioning and traditional and non-traditional cogeneration, and the regression analysis of existing sendout. 1990 Boston Gas Decision, 19 DOMSC at 360.

In the current filing, Boston Gas has expanded the number of markets which it forecasts outside of the traditional end use demand model[29] to include small-scale cogeneration, gas air conditioning, desiccant dehumidification, electric conversion, power generation (including large-scale or non-traditional cogeneration) and natural gas vehicles (Exh. BGC-1, Chart I-A-1). The Company also included a forecast of demand from "Special Projects," based on known contractual agreements (id.). The Siting Council reviews the traditional end use demand model in Section II.D.1 and the non-traditional demand forecasts in Section II.D.2, below.

Boston Gas forecasted sendout for normal year, design year, and design day based on these demand forecasts and an analysis of normalized, daily firm gas sendout for its existing customer base (id., p. 21). In preparing its forecast, the Company first analyzed sendout to existing customers over the most recent 12-month period, and established baseline normal year, design year, and design day sendout forecasts (id.). The Company then added the year-to-year load changes projected in its demand forecasts, and used its gas balance model to develop normal year, design year, and design day forecasts for each year in the forecast period (id.; Tr. 3, p. 5). The Siting Council reviews these steps in Sections II.D.3, 4, 5, and 6, below.

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29/ The traditional end use demand model forecasts demand for end uses which gas companies have traditionally served (e.g. space heating, water heating, cooking, lighting). Separate models were used to forecast markets which developed more recently, and whose dynamics are less well understood (e.g. cogeneration, gas-fired air conditioning, natural gas vehicles).

1. Traditional End Use Demand Forecast

Boston Gas stated that it used an end use model to forecast gross and net[30] increases in demand for gas for traditional end uses in the residential, apartment, and commercial/industrial sectors (Exh. BGC-1, pp. 3-5). The Company indicated that traditional end uses include space heating, water heating, cooling, cooking, lighting, drying, and other (Exh. HO-TD-1).[31]

Boston Gas indicated that its traditional end use model forecasted total energy demand in its service territory for each end use, then determined natural gas' share of this market (Exh. BGC-9, p. 3). The Company stated that it first established base year[32] household and employment figures for its service territory, then developed detailed energy use factors for the base year, and used these data to establish base year energy demand (Tr. 1, p. 20). The Company indicated that it then developed household and employment projections for the forecast period, adjusted the energy use factors for each year, and used these data to produce future year forecasts of energy demand (id., pp. 21-22). The Company stated that it projected gas's market share based on historic market share, life-cycle costs, grid coverage, and non-price factors (Exh. BGC-9, p. 3).

Boston Gas indicated that its traditional end use demand model was jointly developed with Arthur D. Little ("ADL") in 1985, and was updated for the Company's 1988 filing (Tr. 1,

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30/ Boston Gas defined gross additions as demand from new construction or from establishments which switched from oil or electricity to gas (Tr. 1, pp. 69-71). The Company stated that net additions also reflect fuel-switching away from gas and natural conservation in the existing customer base (id.).

31/ Not all end uses were modelled for all sectors. See Sections II.D.1.c,d,e, and f, below.

32/ The Company stated that it used 1987 as its base year (Exh. HO-TD-2).

p. 19). The Company stated that the basic structure of the model is unchanged from that reviewed in the 1990 Boston Gas Decision, but that certain data and assumptions have been updated (Exhs. HO-TD-4, HO-TD-14).[33]

Boston Gas noted that its use of a 1987 base year allows the Company to compare actual gross load additions[34] in 1988, 1989, and 1990 with load additions projected for those years by the Company's end use model based on actual employment and household data. The record shows that the traditional end use model underpredicted gross load additions by 12 percent in 1988, by 20 percent in 1989, and by 32 percent in 1990 (Exh. HO-TD-2, Attachment 1).[35]

In the 1990 Boston Gas Decision, the Siting Council focussed its review of the traditional end use model on the model development, rather than specific model assumptions, and found that the model was reviewable, appropriate, and reliable (19 DOMSC at 368). Therefore, this review will focus on model specifics, and on the data and assumptions that are inputs to the model.

a. Employment and Household Forecasts

Boston Gas stated that it acquired base year employment data for 67 Standard Industrial Classification ("SIC") codes by

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33/ Boston Gas indicated that it updated its employment and household forecasts, residential survey data, fuel share assumptions, energy per employee and energy per household assumptions, fuel price forecasts, fuel switching assumptions and grid coverage assumptions for this filing (Exh. HO-TD-14).

34/ The Company indicated that comparing projected net load growth with actual net load growth would be inappropriate, since actual net load growth includes the effects of weather and other exogenous variables (Exh. HO-TD-23).

35/ The Company argued that the extremely high demand for firm gas which it experienced in 1990 was an aberration due to the perceived oil crisis caused by Iraq's invasion of Kuwait (id.).

city and town from the Massachusetts Department of Employment and Training ("DET") (Tr. 1, pp. 20, 34). The Company stated that it forecasted existing and new employment in each SIC code for each town using Spring, 1991 employment projections provided by Data Resources, Inc. ("DRI") (Exh. HO-TD-7).[36,37] The Company defined existing employment as base year employment less any job losses since the base year and new employment as jobs added since the base year (Tr. 1, pp. 21-22).[38]

Boston Gas stated that its base year household data by building type was based on census data updated by building permit information provided by the cities and towns in the Company's service territory (Tr. 1, p. 20, 34, 51). The Company stated that it projected existing and new household data for each town using Spring, 1991 county-level household forecasts from DRI (Exh. HO-TD-8).[39] The household growth for each town was

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36/ Boston Gas stated that DRI provided it with employment projections covering the forecast period by SIC code and county (Tr. 1, pp. 45-46). Boston Gas forecasted employment by SIC code for each town in its service territory using the DRI growth rates for the county in which the town lies (Exh. HO-TD-7).

37/ The Company also presented employment projections based on DRI's August, 1991 forecasts (Exh. HO-RR-10). These projections were slightly lower than those used in the filing; the August data projected territory-wide employment to grow by 2.09 percent between 1987 and 1996, while the February data predicted 2.39 percent growth over the same period (Exhs. HO-TD-25, HO-RR-10).

38/ For example, if employment in Belmont in the hospital sector declined from the base year, that decline would be reflected in existing employment. If employment in Belmont in the hospital sector increased over the base year, the increment would be considered new employment.

39/ The Company also presented projections based on DRI's August, 1991 forecast (Exh. HO-RR-10). These projections were slightly higher than those used in the filing; the August data projected the number of households territory-wide to grow by 4.26

distributed between building types based on building permit data from 1985 to 1989 (Exh. HO-RR-2).

Boston Gas has combined state and local data with current DRI forecasts to develop employment and household projections tailored to its service territory.[40] Consequently, the Siting Council finds that Boston Gas's forecast of employment and households in its service territory is reviewable, appropriate, and reliable for use in its traditional demand forecast.

b. Fuel Price Forecast

i. Description

Boston Gas stated that its traditional end use demand model incorporated fuel price forecasts in two distinct areas. First, the overall level of fuel prices affected projections of total energy use in each sector through the short run price elasticity (Exhs. HO-TD-11, BGC-9, HO-RR-4). Second, the difference between projected prices for oil and gas (and, to a lesser extent, between projected prices for gas and electricity) are reflected in the market share projections in each sector (id.).

The Company stated that it developed the oil and gas price projections used in its forecast based on projections of refiner acquisition cost of crude ("RACC") prepared by Jensen Associates ("Jensen") in May, 1990 (Tr. 1, pp. 72-73). The Company indicated that it developed Boston area retail prices for #2 and #6 oil offered to various customer types using a model developed

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percent between 1987 and 1996, while the February data predicted 3.53 percent growth over the same period (Exhs. HO-TD-25, HO-RR-10).

40/ The Siting Council notes that, while projections based on a more recent DRI forecast show slightly lower employment growth and slightly higher household growth than the projections used in the forecast, the differences are not significant.

in conjunction with Jensen (id., p. 73). The Company further stated that it developed gas prices for various customer types using a model which takes into account RACC prices and Boston Gas supply portfolio costs (id., p. 74).[41] The Company's witness, Ms. Fenton, stated that the Company had received updated RACC projections from Jensen in September, 1991, and that the new projections were slightly lower than those used in the filing (id.).[42]

ii. Analysis

Boston Gas has developed territory-specific forecasts for oil and gas prices based on current projections from a reliable source. The Siting Council notes that the Company's methodology for forecasting gas prices reflects the current dynamics of gas pricing, thereby ensuring that gas and oil prices rise together.

A comparison of the 1990 and 1991 Jensen reports reveals that Jensen's most recent fuel price projections are slightly lower overall than those used in this forecast. However, the differential between gas and oil price projections has not changed substantially. Therefore, while a forecast based on more recent fuel price projections would probably predict slightly higher overall energy demand in each sector, it is unlikely that gas's market share would change.

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41/ The Company's witness, Ms. Fenton, indicated that the gas costing model escalates domestic wellhead costs using RACC, Canadian wellhead costs based on the market basket defined in the Canadian supply contracts, and transportation prices by inflation (Tr. 1, pp. 74, 76).

42/ The Company submitted copies of both the 1990 and 1991 Jensen reports (Exhs. HO-RR-3, HO-RR-11). Examination of the two reports indicates that Jensen's projections of both oil and gas prices are lower in the 1991 report than in the 1990 report, but that the projected price differential remains approximately the same (id.).

Accordingly, based on the above, the Siting Council finds that the Company's forecast of oil and gas prices for use in the traditional end use demand model is reviewable, appropriate, and reliable.

The Siting Council notes that, although electricity price assumptions have an impact on market share projections, the Company has not indicated how it developed the electricity price assumptions used in the traditional end use demand model. In order for the Siting Council to approve the Company's fuel price forecast in its next filing, the Company must document and justify its electricity price assumptions.

c. Commercial Demand Forecast

Boston Gas stated that it forecasted commercial energy demand for traditional end uses by city, SIC code, end use, and fuel type (Exh. BGC-9, p. 3). The Company indicated that it forecasted commercial demand for six end uses: space heating, water heating, cooling, cooking, lighting, and other (Exh. HO-TD-1).[43] The Company indicated that these end use categories were identified by ADL in 1985, based on available engineering data (Tr. 1, p. 30). Emerging commercial end uses, such as small scale cogeneration and gas air conditioning, were forecast separately (see Section II.D.2, below). The Company forecasted a gross increase in annual commercial demand for gas of 3562 MMcf over the five year forecast period, and a net increase of 2662 MMcf (Exh. BGC-1, Chart I-A-1). The Company noted that this forecast is substantially higher than the Company's 1988 forecast for the 1992 to 1996 period (Exh. BGC-1, p. 5). The Company indicated that this change is due both to a greater projected increase in commercial employment over the years 1992 to 1996, and a higher estimate of the number of

43/ The end use model assumed that gas would not be used for commercial lighting or cooling (Exh. HO-TD-1).

companies which will convert to gas for reasons other than cost (id.).

Under Boston Gas's end use methodology, the Company first determines base year energy demand, then forecasts commercial energy demand as the sum of forecasts of existing commercial energy demand and new commercial energy demand (Tr. 1, p. 26). A brief explanation of how the Company developed each of these components is provided below.

i. Base Year Energy Demand

The Company stated that it developed detailed base year energy factors by city, SIC code, end use, and fuel type for the commercial sector (Exh. HO-TD-16). The Company indicated that it calculated base year average energy use per employee for commercial SIC codes using 1987 state employment data from DET and total state commercial energy use data from the U.S. Department of Energy ("DOE") (Exh. HO-TD-16). The Company then developed industry-specific energy use factors by adjusting the average energy use factors based on 1985 ADL data (Exh. HO-TD-16; Tr. 1, p. 24). The industry-specific energy use factors were then broken down by end use (id.).[44] The Company stated that it used 1987 employment figures by SIC code and city to determine energy use by city and SIC code (Tr. 1, p. 24). Finally, the Company distributed the energy demand by end use between gas, electricity, and oil based on its own and electric company records (id., pp. 24-25).

44/ Ms. Fenton indicated that the Company was considering the possibility of updating its relative energy intensity and end use estimates based on MassSave data and the results of metering studies (Tr. 1, pp. 39-40).

ii. Existing Commercial Demand

The Company stated that existing commercial energy demand for each SIC code was forecast by multiplying energy use factors[45] and existing employment projections for that SIC code (id., p. 27).[46] The Company indicated that the energy use factors for each year were calculated by adjusting the previous year's energy use factors for short-run price elasticity[47] and long term conservation (id., p. 26). The Company estimated that conservation would reduce average energy use per commercial employee by 0.4 percent annually, based on a 1985 study by ADL (Exhs. HO-TD-10, Attachment 1, HO-DM-3, Attachment 1). The Company indicated that this estimate reflected the effects of mandated appliance efficiency standards and long-run price elasticities (Exhs. HO-TD-20, HO-TD-22). The Company stated that it had not performed any study to verify or update its conservation assumptions (Tr. 1, p. 64).

The Company stated that it assumed that gas's share of existing energy demand would remain constant for all end uses except space and water heating (Exh. HO-TD-6). The Company estimated that five percent of existing commercial space heating systems would be retired each year, and that those systems with central boilers or furnaces were candidates for fuel-switching (Exh. HO-TD-18). Of these, the Company assumed that 20 percent would convert from oil to gas regardless of fuel price; the rest

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45/ As noted in section II.D.1.c.i, above, energy use factors for a particular SIC code indicate the average energy use per employee in that SIC code, broken down by end use.

46/ As discussed in Section II.D.1.a, above, existing employment is defined as base year employment less any job losses since the base year.

47/ The Company used a short-term price elasticity of -0.2 for all sectors based on assumptions provided by ADL (Exh. HO-TD-10).

were distributed between gas and oil based on building size, equipment type, and life-cycle costs (Exhs. HO-TD-12, HO-TD-18).

The Company stated that it expected 20 percent of commercial and industrial customers to switch from oil to gas regardless of price, because of concerns about liability for oil storage tanks, air emissions compliance, fuel reliability, and fuel price stability (Exh. HO-TD-12). The Company indicated that it had increased this estimate from the 12 percent figure used in its 1988 filing, based on market research and conversations with field personnel (id.). Ms. Fenton indicated that she had analyzed the sensitivity of the commercial demand forecast to a range of figures between 12 and 25 percent, and found that the choice of figure had a "significant impact" on commercial demand (Tr. 1, p. 58). Ms. Fenton stated that she was "intuitively comfortable" with the 20 percent figure, and did not think it was prudent to use a figure greater than 20 percent without reviewing the results of a forthcoming market research survey (id., pp. 58-59). Ms. Fenton noted that the original 12 percent figure was also judgmental (id., p. 58).

iii. New Commercial Demand

The Company indicated that new commercial energy demand for each SIC code was calculated as the product of energy use factors for that SIC code and new employment projections[48] for that SIC code (Tr. 1, p. 27). The Company indicated that new energy use factors for a given year were calculated as 90 percent of the existing energy use factors for that year, to account for building shell improvements and more efficient new equipment (id., p. 62; Exh. HO-TD-10).

The Company assumed that gas retained its historical market share of the new commercial energy demand in all end uses

48/ As discussed above, new employment for a given city or town and SIC code is employment in that SIC code in excess of base year employment.

except space and water heating (Exh. HO-TD-6). The Company stated that space and water heating demand were distributed between self-contained gas, heat pump and electric resistance units and central systems based on ADL estimates (id.). The Company also stated that the central systems were further distributed between gas and oil based on a life-cycle cost comparison (id.).

iv. Analysis

Boston Gas has developed a detailed end use model to forecast commercial demand for gas to meet traditional end uses. The model explicitly projects total energy demand in the Company's service territory as a preliminary to predicting the demand for natural gas. This modelling approach is appropriate in that it recognizes that Boston Gas is in direct competition with electric and oil companies for market share in many end uses. Further, the Siting Council found this model to be reviewable, appropriate, and reliable in the 1990 Boston Gas Decision. However, the Siting Council has some concerns with the Company's implementation of the model in this forecast filing.

First, the Company relies on data developed in 1985 to determine the relative energy intensity of various SIC codes, and the distribution of end uses within these SIC codes. These weights are important inputs of the end use model, and should be updated frequently to reflect change within various commercial sectors. However, while the Siting Council is concerned about the Company's reliance on energy intensity data which was six years old at the time of the filing, we recognize that the technological changes which lead to shifts in relative energy intensity occur over long periods of time, and are less likely to occur during a recession. Consequently, the 1985 energy intensity data is likely to be minimally reliable for use in this model.

Second, the Company has updated its estimates of the percentage of consumers who will replace retired oil burners with gas burners, regardless of price, from 12 percent to 20 percent for this filing. The Company has indicated that its choice of 20 percent was judgmental, based on market research and conversations with field personnel. While it is clearly appropriate, and even necessary, for the Company to update assumptions which no longer seem to be accurate, the Company should document the reasoning behind such updates in a more formal manner so that the Siting Council can better evaluate the reliability of the new figures, especially when such assumptions are recognized as being particularly significant.

Third, the Company has indicated that its long-run conservation factor is intended to reflect the effects of both long-run price elasticity and mandated appliance efficiency standards in its existing commercial forecast. However, this conservation factor has not been updated since 1985, and may not reflect efficiency standards mandated since that time. Siting Council regulations require that forecasts reflect federal and state mandated efficiency standards. 980 CMR 7.09(2)(d). The Siting Council notes that since the Company adjusts total energy sales for conservation, this adjustment must include efficiency standards mandated for electric as well as gas appliances. The Siting Council also notes that the effects of long-run price elasticities should be dependant on price, whereas the Company's long-run conservation factor clearly is not.

Finally, the Company forecasts its market share of five discrete end uses and "other", a category which encompasses all other commercial energy use in the service territory. The Siting Council is concerned that the "other" category may, to a limited extent, overlap with the Company's forecasts of small-scale cogeneration, desiccant dehumidification, and natural gas vehicles.[49] Since "other" contributed only 3 percent to the commercial demand for natural gas in the base year, the possibility of such an overlap does not seriously affect the reliability of this forecast. However, when the Company updates its end use distribution, it should either isolate end uses which it forecasts separately, or incorporate the "non-traditional" end uses into its end use forecast.

Despite these concerns, Boston Gas has presented a well-documented forecasting model with significant strengths to the Siting Council for review. The implementation concerns which we have identified are not so significant as to undermine the model's reliability. Further, the Siting Council has previously accepted the Company's employment and fuel price forecasts (see Sections II.D.1.a and b, above). Consequently, for the purposes of this review, the Siting Council finds that the commercial forecast generated by the Company's traditional end use model is reviewable, appropriate, and minimally reliable for use in developing normal year, design year, and design day sendout forecasts. However, in order for the Siting Council to approve the Company's commercial demand forecast in its next filing, Boston Gas must (1) update its energy intensity factors based on data more recent than 1985, (2) provide a more detailed justification of its assumption on fuel-switching for non-price reasons, (3) reflect mandated appliance efficiency standards in its forecast, and (4) either explicitly forecast the effects of long-run price changes on energy demand, or explain why it is not appropriate to do so.

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49/ The gas air-conditioning forecast clearly does not overlap with the end use model, since the Company forecasts cooling as a discrete end use in the end use model, but assumes that gas has no share of the market.

d. Industrial Forecast

i. Description

Boston Gas stated that it forecasted industrial energy demand for two end uses: space heating and other (Exh. HO-TD-1). The Company indicated that these end use categories were devised by ADL in 1985, based on available engineering data (Tr. 1, p. 30). Industrial sales to large customers, such as cogenerators, were forecast separately (see Section II.D.2.f and g, below). The Company forecasted a gross increase in annual industrial demand of 712 MMcf over the five year forecast period, and a net increase of 180 MMcf (Exh. BGC-1, Chart I-A-1).

The Company stated that it used a single model to forecast industrial and commercial demand (Tr. 1, p. 38). The Company indicated that base year average energy per industrial employee was calculated using DET and DOE data, and that weightings of energy use by SIC code were developed from 1981 data from the U.S. Department of Commerce ("DOC") (Exhs. HO-TD-16, HO-DM-3, Attachment 1, p. 7). The Company stated that it estimated that conservation would reduce average energy use per industrial employee by 0.7 percent annually (Exh. HO-TD-22, Attachment 3). The Company further indicated that it estimated industrial energy use factors for new employment in a given year as 80 percent of the energy use factors for existing employment in that year (Exh. HO-TD-10).

ii. Analysis

Boston Gas's forecast of demand in the industrial sector is identical in structure to its commercial forecast. Consequently, the industrial forecast exhibits the same structural strengths and weaknesses as the commercial forecast, described in Section II.D.1.c, above.

However, the Siting Council notes that its concerns about the age of the relative energy intensity data are deepened with respect to the industrial forecast, since the industrial data dates from 1981.[50] The Siting Council also notes that industrial demand for gas is split approximately evenly between the space heating and "other" end uses (Exh. HO-TD-15, Attachment 1). In previous cases, the Siting Council has criticized the use of miscellaneous categories which make up a substantial percentage of a sector's demand. Nantucket Electric Company, 21 DOMSC at 208, 237 (1991); Massachusetts Municipal Wholesale Electric Company, 20 DOMSC at 1, 31 (1990); Massachusetts Electric Company, 18 DOMSC at 295, 320-321 (1989). In updating its end use data, the Company should, at a minimum, ensure that the end uses forecasted outside the traditional demand model do not make up a substantial portion of the base year "other" demand.

Consequently, while the Siting Council finds that Boston Gas's industrial end use forecast is reviewable and appropriate, we also find that the Company has not demonstrated that this forecast is reliable for use in developing normal year, design year, and design day sendout forecasts. In order for the Siting Council to approve the industrial end use forecast in the next forecast filing, the Company must update the energy intensity and end use distributions upon which this forecast relies, or demonstrate that its old distributions remain reliable.

e. Residential Forecast

i. Description

Boston Gas stated that it forecasted residential energy demand for five end uses (space heating, water heating, cooking, drying, and other), two building sizes (single family and two to four family) and two customer types (heating and non-heating) (Exh. HO-TD-1). The end use model assumed that natural gas had no share of the "other" end use market (id.). Boston Gas

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50/ The Siting Council notes that DOC performs its Census of Manufacturers every five years, and that 1986 data, gathered in the 1987 census, should have been available to the Company at the time of the filing (Exh. HO-DM-3, p. 7).

stated that sales to residential units of more than four households were forecast separately as the apartment sector (see section II.D.1.f, below).

Boston Gas forecasted a gross increase in residential heating demand of 3121 MMcf over the five year forecast period, and a net increase of 926 MMcf (Exh. BGC-1, Chart I-A-1). The Company forecasted no gross increase in residential non-heating demand, and a net loss of 255 MMcf over the forecast period (id.). The Company noted that this forecast is substantially higher than the Company's 1988 forecast for the same period, due both to new assumptions about the age of existing equipment and a larger projected variance between the prices of oil and gas (id., pp. 4-5).

As with the commercial and industrial forecasts, residential energy demand is the sum of existing and new residential energy demand (id.). The Company indicated that existing demand for residential energy in a given year was calculated as the product of existing households and energy use per household (id.). Energy use factors for each year were the base year energy use factors, adjusted for the effects of short run price elasticity and stock replacement (Exh. HO-TD-10). The Company indicated that, instead of using a long term conservation factor for existing residential stock, it adjusted energy factors based on the increase in efficiency seen when customers replace old equipment with new equipment (Tr. 1, p. 91).

The Company stated that it developed base year residential energy factors by town, building type, end use, and fuel type (Exh. BGC-9, p. 2; Tr. 2, pp. 10-11). The Company indicated that it obtained base year housing data from the Bureau of the Census, and data on total base year residential energy use from DOE (Exh. HO-TD-16). The Company indicated that it used census data, updated by building permits, to break out household data by building type (Tr. 1, p. 51).

The Company indicated that it adjusted its share of the existing residential energy market based on equipment age and replacement trends (id., p. 84). The Company stated that it estimated the number of each type of appliance which would be retired each year based on equipment age data from its 1989 residential saturation survey (id.). The Company estimated the likely conversion rates between fuels for each type of appliance based on replacement trends data from a 1990 survey performed by Decision Research Corporation (id., p. 85).[51]

Boston Gas stated that new residential energy demand was calculated as the product of new households and energy use per household (Exh. HO-RR-4). The Company indicated that energy use factors for the new residential market were the existing energy use factors for that year, adjusted for new equipment efficiency (Exh. HO-TD-10).

The Company indicated that it estimated its share of the new residential energy market based on a 1987 analysis by ADL, which estimated gas' likely share of centrally-cooled and non-centrally-cooled households (Tr. 1, p. 79).[52] The Company stated that it adjusted ADL's analysis to reflect new estimates of relative fuel prices and the Company's intention to aggressively target the new residential market (Tr. 1, pp. 80-82). The Company indicated that it expected gas' share of the new residential space heating market to grow from 25 percent in 1987 to 40 percent in 1996 (Exh. TD-6, Attachment 1). Of these new

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51/ The Company stated that Decision Research Corporation annually surveys customers, non-customers, and recent equipment replacers in the Boston Gas Service territory to determine likely replacement trends (Tr. 1, pp. 85-86). The Company indicated that it may, in the future, have the survey taken every other year (id., p. 85).

52/ The Company indicated that in centrally cooled households, the possible heating technologies are gas and electric heat pumps. In non-centrally-cooled households, possible heating fuels are gas, oil, and electricity (Tr. 1, p. 79).

customers, 91 percent were expected to have gas water heating, and 50 percent were expected to use gas for cooking (id.). The Company stated that it generally does not hook up new non-heating customers (Tr. 1, p. 90).

ii. Analysis

The Siting Council has previously accepted the Company's household and fuel price forecasts (see Sections II.D.1.a and b, above).

Boston Gas's residential demand forecasting model is similar to the Company's other end use models, and incorporates the strengths of its commercial/industrial models. Further, the Company's determination of existing market share is based on up-to-date, territory-specific survey data. There is no potential overlap between traditional residential end uses and the separate non-traditional forecasts. However, the Siting Council notes that the Company's forecast for the new residential market reflects its intention to aggressively increase market share. To the extent that the Company's marketing plans materialize, the Company's residential forecast will prove reliable. However, the Company's expectation of a significant increase in new market share is subject to uncertainty. Thus, the Company should monitor its penetration of the new residential market and verify its actual share of this market in its next filing.

Based on the above, the Siting Council finds that the Company's forecast of residential demand is reviewable, appropriate, and reliable for use in developing normal year, design year and design day sendout forecasts.

f. Apartment Forecast

i. Description

Boston Gas indicated that it defines the apartment house sector as residential buildings consisting of more than four households (Tr. 1, p. 52; Exh. HO-TD-8, Attachment 1).[53] The Company stated that it forecasted energy demand in the apartment sector for five end uses: space heating, water heating, cooking, drying and other (Exh. HO-TD-1). The Company forecasted a gross increase in annual demand in the apartment sector of 544 MMcf over the five year forecast period, and a net increase of 106 MMcf (Exh. BGC-1, Chart I-A-1). The Company noted that this forecast is substantially lower than the Company's 1988 forecast for the same time period, due primarily to substantially lower household projections for the apartment and condominium markets (id., p. 5).[54]

The Company stated that it forecasted demand in the apartment sector using a model similar to the commercial/industrial model (Tr. 1, p. 79).[55] New and existing energy demand were forecast based on projections of new and existing households in the apartment sector (Exh. BGC-1, p. 4). As it did in the commercial/industrial model, the Company adjusted existing energy use factors for short run elasticity and long term conservation (Exh. HO-TD-10). The Company stated that it assumed energy use per household would decline by .2 percent annually over the forecast period, based on estimates provided by ADL (id.). The Company indicated that it estimated energy use

53/ The Siting Council notes that this definition includes condominiums, as well as rental units.

54/ The Company stated that in 1988, it predicted that net demand for gas in the apartment sector would increase by 1368 MMcf between 1992 and 1996 (Exh. BGC-1, p. 5). The Company indicated that in its 1988 forecast, it assumed that the apartment sector would grow by 77,818 households between 1986 and 1996 (Exh. HO-TD-13). In the current filing, the Company assumed that the apartment house sector would grow by 13,686 households between 1987 and 1996 (id.).

55/ Ms. Fenton noted that the demand estimation and fuel switching algorithms were identical to those used in the commercial/industrial model (Tr. 1, p. 79).

factors for new households in a given year as 75 percent of the energy use factors for existing households in that year (id.).

ii. Analysis

Boston Gas's forecasting methodology for the apartment sector incorporates the strengths of its commercial/industrial methodology, while overcoming some of its weaknesses. The Company's estimates of base year energy use factors are based on recent and reliable data. Further, there is no potential overlap between the traditional end uses modelled in this forecast and the non-traditional forecasts. However, the Siting Council notes that the Company uses long-run conservation estimates developed by ADL in 1985 and reviewed, but not updated, since then. The Company should review these estimates before its next filing to determine whether they remain reasonable in light of current practice and new federal and state efficiency standards.

Based on the above, the Siting Council finds that the Company's forecast of demand in the apartment sector is reviewable, appropriate, and reliable for use in developing normal year, design year and design day sendout forecasts.

g. Conclusions on the Traditional Demand Forecast

The Siting Council has found that Boston Gas's forecasts of employment, households, and oil and gas prices are reviewable, appropriate, and reliable for use in its traditional demand forecast. Further, the Siting Council has found that the Company's forecasts for the residential and apartment sectors are reviewable, appropriate, and reliable for use in developing normal year, design year, and design day sendout forecasts. The Siting Council also has found that the Company's commercial forecast is reviewable, appropriate, and minimally reliable for use in developing normal year, design year, and design day sendout forecasts. Finally, the Siting Council has found that, while the Company's industrial end use forecast is reviewable and appropriate, the Company has not demonstrated that this forecast is reliable for use in developing normal year, design year, and design day sendout forecasts.

Consequently, on balance, the Siting Council finds that the Company's forecast of demand for gas to meet traditional end uses in the residential, apartment, commercial and industrial sectors is reviewable, appropriate and minimally reliable for use in developing its normal year, design year, and design day sendout forecasts.

However, the Siting Council is deeply concerned about the apparently increasing trend towards underforecasting demonstrated by this model. The Company should monitor forecasted and actual load growth by sector to determine the source of this underforecasting. In order for the Siting Council to approve the Company's traditional end use demand forecast in its next filing, the Company must include updated comparisons between forecasted and actual load disaggregated by customer class, an analysis of the likely sources of the underforecasting, and an action plan for improving the model.

The Siting Council also notes that comparisons with demand forecasts prepared for the previous filing demonstrate the sensitivity of this end use model to forecasts of economic and other assumptions. Siting Council regulations require that forecasting methodologies be designed to accommodate sensitivity testing of major assumptions and parameters. 980 CMR 7.09(2)(a). The Siting Council therefore encourages the Company to develop alternative demand scenarios based on a reasonable range of economic and other key assumptions.

2. Non-Traditional Demand Forecasts

a. Small-Scale Cogeneration

i. Description

Boston Gas forecasted that its load growth in the small-scale cogeneration market[56] would be 301 MMcf over the five-year forecast period (Exh. BGC-1, Chart I-A-1).[57] The Company noted that this forecast was lower than its 1988 forecast for the same period, and attributed the difference to more accurate estimates of load per installation by building type (id., p. 8). The Company stated that its forecast assumed small-scale cogenerators to be year-round gas customers (Exh. HO-SC-5; Tr. 1, p. 133).

Boston Gas stated that it uses a three-step process to forecast new small-scale cogeneration load, as follows: (1) estimation of market potential, (2) determination of gas penetration, and (3) determination of gas load (Exh. BGC-1, pp. 6-7). The Company indicated that it estimated market potential for 17 building types,[58] three building sizes, and two electric company service territories as the product of employment and thermal load (Exhs. HO-SC-6, BGC-1, p. 7). The Company stated that it used energy forecasts from its traditional

56/ The small-scale cogeneration market consists of facilities which install cogeneration to meet their own needs. The non-traditional or large-scale cogeneration market consists of large projects built specifically to generate electricity for sale to electric utilities.

57/ The Company did not differentiate between gross and net load additions in its non-traditional demand forecasts (Exh. BGC-1, Chart I-A-1).

58/ The Company indicated that these building types were: nursing homes, hospitals, schools, colleges, hotels, industrial plants, health clubs, financial/insurance/real estate, business services, government, transportation/communications/utility, miscellaneous services, food stores, eating establishments, other retail, prisons, and apartments (Exh. HO-SC-6, attachments).

commercial end use model to determine thermal load for each building size and type (id.).

The Company stated that it determined market penetration for each year based on the assumption that establishments which were replacing a boiler in that year were candidates for cogeneration (Exh. HO-SC-6). The Company estimated the percentage of boiler-replacing establishments which would invest in cogeneration in a given year using a model developed by ADL to analyze payback periods by building type, size, and electric company territory (Exh. HO-SC-6; Tr. 1, pp. 110-114). Ms. Fenton noted that the Company had been unable to locate data concerning investment preferences for small-scale cogeneration or other emerging gas technologies, and therefore had used the ADL model, which was based on an investment preference curve for a mature HVAC technology (Tr. 1, pp. 110-111).

The Company further indicated that, after estimating gross load growth based on market potential and penetration, it adjusted the load based on accessibility to gas mains, and subtracted out the existing load of Boston Gas customers who had already invested in small-scale cogeneration (id., p. 7.)

Boston Gas indicated that it acquired information on the number, size, and type of buildings in its service territory from DET and from Trinet, Inc. ("Trinet"), a company which maintains target marketing databases (id., p. 22; Exh. BGC-1, p. 7). The Company estimated the presence of boilers in each building type based on northeast regional data from the Gas Research Institute ("GRI") and the Energy Information Association ("EIA") (Exh. HO-SC-6). The Company stated that it used building stock age data from GRI as a proxy for equipment age (Exh. BGC-1, p. 7).

Boston Gas used its model to "backcast" small-scale cogeneration load additions for 1988, 1989, and 1990 and compared these results with actual load additions for these years (Exh. HO-SC-8). Actual load additions were somewhat lower than those forecast in 1988 and 1989, and almost exactly as forecast in 1990 (id.).[59] Ms. Fenton attributed the higher load growth in 1990 to an increase in customer acceptance of cogeneration technology (Tr. 1, p. 132).

The Company also submitted a review of Boston Gas's cogeneration forecasting methodology, conducted by RCG, Hagler/Bailly ("RCG"), which concluded that the forecast represented "best practice" standards, while offering specific suggestions for improvement (Exh. BGC-8). The Company indicated that it had implemented some of RCG's suggestions (Exh. HO-SC-6).

ii. Analysis and Compliance with Order 4

In the 1990 Boston Gas Decision, the Siting Council found that, while the Company had developed a reviewable and appropriate preliminary methodology for forecasting small-scale or traditional cogeneration, the Company's forecast was weakened by its lack of reliable input data (19 DOMSC at 372). Consequently, in Order Four of that decision, the Siting Council ordered the Company to:

> Include in its next forecast filing territory specific studies designed to develop a reliable database of building types, energy use, and market potential for traditional cogeneration development (id.).

For this filing, the Company acquired current, territory-specific data on building types and sizes. In addition, it developed energy use estimates using its commercial/industrial end use model, which the Siting Council has accepted (see Sections II.D.1.c and d, above). Further, the Company's market potential estimates are based on regional data from GRI and EIA, and payback estimates developed by RCG. Accordingly, the Siting

59/ The Company forecast load additions of 32 MMcf in 1988, 48 MMcf in 1989, and 42 MMcf in 1990 (Exh. HO-SC-8). Actual load additions were 26 MMcf in 1988, 25 MMcf in 1989, and 45 MMcf in 1990 (id.).

Council finds that the Company has complied with Order Four of the 1990 Boston Gas Decision.

The Siting Council notes that Boston Gas has developed a sophisticated forecast methodology for small-scale cogeneration which recognizes differences in payback to potential customers of different sizes in different businesses and electric company territories. However, we have concerns regarding the Company's use of ADL's investment preference curve to translate payback periods into penetration estimates. ADL developed this preference curve from studies of the acceptance of a mature HVAC technology, while the Company has indicated that customer acceptance and familiarity with small-scale cogeneration technology is still growing. The Siting Council accepts that the ADL curve may be the best tool currently available to the Company without the commissioning of a study aimed at determining market-specific penetration rates.[60] Further, the results of the Company's backcasting indicate that the forecast provides reasonably accurate predictions of load growth, especially in more recent years.

Consequently, the Siting Council finds that the Company's forecast of load growth in the small-scale cogeneration market is reviewable, appropriate, and reliable for use in developing normal year, design year and design day sendout forecasts. However, the Company should monitor cogeneration load additions to ensure that the ADL curve continues to accurately represent customer investment decisions.

b. <u>Gas-Fired Air Conditioning Forecast</u>

i. <u>Description</u>

Boston Gas forecasted that its load growth in the gas-fired air conditioning market would be 211 MMcf over the forecast

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60/ Ms. Fenton indicated that the Company has discussed with RCG the possibility of undertaking this research, but has not yet made a decision to do so (Tr. 1, p. 113).

period (Exh. BGC-1, Chart I-A-1). The Company noted that this forecast was higher than its 1988 forecast for the same period, due primarily to the increased number of building types considered as possible gas-fired air conditioning customers (id., pp. 8-9).

The Company indicated that it has revised its forecasting methodology since the 1990 Boston Gas Decision, and that its gas-fired air conditioning forecast is now identical in structure to the small-scale cogeneration forecast (id., p. 8; Tr. 1, p. 134). The Company stated that it forecasted gas-fired air conditioning load for 14 building types[61] selected by the Company's technical applications group (Exh. HO-GF-2, Attachment 1; Tr. 1, p. 135). The Company indicated that it acquired building size, type, and electric company territory information from DET and Trinet, generated estimates of cooling load by building size and type using its end use model, and acquired data on the presence of chillers in buildings, and likely replacement rates, from GRI and EIA (Exhs. BGC-1, p. 9, HO-GF-1). The Company stated that company engineers developed payback periods by application size and territory (Exh. HO-GF-1).

Boston Gas used its model to "backcast" load additions for 1988, 1989, and 1990, and compared these results with actual load additions for those years (Exh. HO-GF-6). Actual load additions fell far short of the forecast in all three years (id.).[62] Ms. Fenton stated that the Company's forecast methodology assumes a

61/ The Company indicated that these building types were: nursing homes, hospitals, schools, colleges, hotels, health clubs, museums, financial/insurance/real estate, business services, government, transportation/communications/utilities, miscellaneous services, food stores, and other retail (Exh. HO-GF-1).

62/ The Company forecast load additions of 62 MMcf in 1988, 64 MMcf in 1989, and 39 MMcf in 1990; actual load additions were 2 MMcf in 1988, 3 MMcf in 1989, and 16 MMcf in 1990 (Exh. HO-GF-6).

level of marketing intended to "maximize the penetration in that new market," and stated that actual load additions between 1988 and 1990 reflect a lower level of marketing activity (Tr. 1, pp. 137-138). Ms. Fenton indicated that the Company has increased its marketing of gas-fired air conditioning technology since 1989 (id., p. 137).

ii. Analysis

In the 1990 Boston Gas Decision, the Siting Council found that the Company had failed to establish that its forecast of gas-fired air conditioning load growth was a reviewable, appropriate, and reliable input to its sendout forecast (19 DOMSC at 373-374). In response to Siting Council concerns, the Company has developed a new forecasting model based on its small-scale cogeneration forecast. The Siting Council finds that this methodology, based on estimates of market potential and penetration, is reviewable and appropriate for forecasting load growth from gas-fired air-conditioning.

However, the Siting Council has serious concerns about the use of the ADL preference curve to determine market penetration rates in this forecast. As noted above, the ADL curve represents customer acceptance of a mature technology; gas-fired air conditioning has not yet reached that stage of acceptance in Boston Gas's service territory, as evidenced by the 1988 through 1990 load growth figures. The Company has asserted that increased marketing activity will result in load growth which more closely approaches the forecast; however, the record contains no information which would tend to confirm that assertion. Therefore, the Siting Council makes no finding as to the gas-fired air conditioning forecast's reliability for use in developing normal year, design year, and design day sendout forecasts. In order for the Siting Council to approve the Company's gas-fired air conditioning forecast in its next filing, the Company must either offer more persuasive evidence that the

ADL curve is applicable to this market, or develop another, more justifiable, method of estimating market penetration rates for this technology.

c. Desiccant Dehumidification

i. Description

Boston Gas identified desiccant dehumidification as a new market which is forecast to bring load additions of 100 MMcf over the forecast period (Exh. BGC-1, Chart I-A-1 and p. 11). The Company described desiccant dehumidification as a gas-fired technology which increases the efficiency of electric air conditioning by extracting moisture from air before it enters the air conditioning system (Tr. 2, pp. 16-17). The Company indicated that, to date, supermarkets have been the primary market for this technology, both because they have higher cooling requirements per square foot than other establishments, and for aesthetic reasons (id., pp. 17-18). The Company stated that the desiccant dehumidification load would occur primarily between April and September (id., p. 19).

Boston Gas stated that it used a three-step process to forecast load growth due to desiccant dehumidification (Exh. BGC-1, p. 11). First, the Company determined the number of large supermarkets on gas mains in its service territory, using data from Trinet (id., p. 11, Exh. HO-DM-1).[63] Second, the Company used the ADL preference curve to estimate the penetration rate of desiccant dehumidification as 13 percent of the potential market in each year (Exh. BGC-1, pp. 11-12). Third, Boston Gas estimated the resulting load additions as 1.75 MMcf per installation, based on previous installations (id., p. 12). The Company noted that, since desiccant dehumidification is a front-

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63/ The Company indicated that only supermarkets with over 40 employees, or 10,000 square feet of floor space, were considered as potential candidates for this technology (Exh. BGC-1, p. 12).

end, rather than a replacement, for electric air conditioning, it can be added at any time during the life of an air conditioning unit (Tr. 2, p. 20).

The Company stated that it adjusted its projected load growth for 1991 and 1992 based on marketing leads, assuming that these two years would serve as a ramp-up period during which the technology would gain acceptance (id., p. 21; Exh. HO-DM-1). Ms. Fenton indicated that the timing of the market was uncertain, and that she intended to confirm the market penetration projections with market research (Tr. 2, pp. 25-26).

ii. Analysis

The Siting Council recognizes the efforts which Boston Gas is making to identify new markets as they emerge, and to formally project load growth in these markets. Boston Gas has used a simplified version of its cogeneration and air conditioning models to forecast load growth from desiccant dehumidification. As noted above, the Siting Council has concerns about the use of the ADL preference curve, which is based on a mature HVAC technology, to forecast load growth for very new technologies, such as desiccant dehumidification. The Company has addressed some of these concerns by projecting a two-year ramp-up period, during which the technology is introduced at a rate slower than that forecasted by its model. However, the Company has stated that it is uncertain about the timing of this market. The Siting Council shares this uncertainty. Therefore, while the Siting Council finds that the Company's desiccant dehumidification forecast is reviewable and appropriate, it makes no finding as to the reliability of this forecast for use in developing normal year, design year, and design day sendout forecasts. In order for the Siting Council to approve the Company's desiccant dehumidification forecast in its next filing, the Company must either offer more persuasive evidence that the ADL curve is applicable to new technologies, or develop another, more justifiable, method of estimating market penetration rates for this technology.

d. Electric Conversion Forecast

i. Description

Boston Gas projected that the electric conversion market would add 719 MMcf from electric-to-gas fuel-switching during the forecast years 1992-1996 (Exh. BGC-1, p.10). The Company described the electric conversion market as including electric-to-gas fuel switching for residential and commercial/industrial end uses, including heating, water heating, cooking, drying, and central cooling (id.). Boston Gas indicated that it based its expectation of an emerging electric conversion market on the Integrated Resource Management ("IRM") regulations promulgated by the Siting Council and the DPU (id.).[64] 980 CMR 12.00 et seq.

In order to estimate load additions in the electric conversion market, Boston Gas first determined the total existing electric load that could be converted (Exh. BGC-1, p. 10). The Company indicated that it obtained total existing electric load figures for heating, water heating, cooking, drying and cooling from its base year demand model (Exh. HO-EF-3). Boston Gas then adjusted this load for efficiency differentials between gas and electricity to determine the maximum electric-to-gas potential (id.).[65] The Company stated that this calculation yields the

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64/ The IRM regulations require electric companies in the IRM process to identify and quantify for each end-use with fuel switching potential, the estimated additional capacity and energy savings associated with fuel switching. 980 CMR 12.00 (9)(a)(2). In addition, the Siting Council notes that a proceeding is currently pending before the DPU, DPU 90-261-A, regarding the issue of mandatory fuel switching programs (see Exhs. HO-EF-7, HO-EF-10).

65/ Electric and gas efficiencies were obtained from ADL.

total potential gas load that could be converted from electricity (id.).

Boston Gas stated that it then adjusted the potential gas load to reflect the load that is presently accessible by gas pipelines, based on grid coverage percentages obtained from Boston Gas engineering personnel (Exh. HO-EF-3). The Company indicated that it further adjusted the resulting load to account for the fact that it is not likely to convert 100 percent of this market potential for various reasons, including (1) the technical feasibility of converting fuels, (2) relative life-cycle costs, (3) customer preference or bias, and (4) owner/tenant status (Exhs. BGC-1, p.10, HO-EF-3). The Company stated that the market penetration rates used in this calculation were subjective estimates (Exh. HO-EF-8). The Company asserted that at this point in time there are no studies that the Company could look to in developing market penetration rates for the electric conversion market (Tr. 2, p. 43). Ms. Fenton testified that it was her belief that Boston Gas is the only utility in Massachusetts that has attempted to quantify and forecast the electric conversion market (id.).

The Company estimated annual incremental loads from the electric conversion market by distributing the total expected load from that market over a 25-year period (Exh. HO-EF-8). The Company stated that, due to the lack of information concerning the timing of electric company DSM programs, estimated load additions from the electric conversion market were allocated evenly over the forecast period (Tr. 2, p. 46).

The Company noted that its electric conversion forecast included only electric-to-gas conversions occurring as a direct result of electric company-sponsored DSM programs, and did not include "natural" electric-to-gas conversions expected to occur without electric company intervention, as these conversions were incorporated into the Company's traditional end use forecast (Exhs. HO-EF-1, HO-EF-2). Boston Gas indicated that the electric conversion forecast assumed that electric utilities will offer their customers incentives at a level that will be sufficient to convince them to switch selected end uses from electricity to gas (Exh. HO-EF-4). The Company further stated that this forecast assumed that electric companies would pay for equipment costs and installation costs, as well as any main or service costs. (Tr. 2, p. 45). However, Ms. Fenton testified that she was not aware of any electric company in the Boston Gas service territory that had voluntarily undertaken a fuel-switching program in response to the IRM regulations, or had any plans to undertake one (id., p. 38). In addition, the Company stated that the forecast assumed that Boston Gas would not provide incentives to electric customers to switch to gas beyond those it would offer to "naturally" converting customers (Exh. HO-EF-5). Boston Gas further stated that the electric conversion forecast assumed that avoided electric costs are greater than avoided gas costs (Exh. HO-EF-11).

Boston Gas stated that its forecast was based on an assessment of the relative societal costs of electric and gas alternatives as conducted by Resource Insight,[66] rather than on a detailed end use econometric model (Exh. HO-EF-6). The Company stated that Resource Insight's study strongly supported the conclusion that Massachusetts electric utilities should include fuel-switching in their demand-side programs, citing what it called the high benefit-cost ratios for many of the fuel-switching applications (id., p. 3).

Ms. Fenton testified that it was "possible" that there would be no electric conversion market in 1992, given the length of time necessary for an electric company to develop a

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66/ Resource Insight's findings are contained in a report entitled "Analysis of Fuel Substitution as an Electric Conservation Option Based on the Avoided Costs of Boston Gas Company, Boston Edison Company, and Massachusetts Electric Company", dated December 22, 1989 (Exh. HO-EF-6, Attachment 1).

conservation program (Tr. 2, p. 39). Boston Gas projected load additions of 111 MMcf for 1992 in its electric conversion forecast (Exh. BGC-1, Chart I-A-1).

ii. Analysis

The Siting Council notes that this is the first time that any gas company in the Commonwealth has presented a specific forecast for an electric conversion, or fuel-switching market. Boston Gas expects this market to emerge as a result of "regulatory initiatives" such as the IRM regulations and the current case before the DPU in Docket No. 90-261-A.

While the IRM regulations require electric companies to identify and quantify estimated additional capacity and energy savings associated with fuel switching, electric companies are not required to implement fuel-switching programs. 980 CMR 12.00(9). Indeed, in its final order on the IRM rulemaking, the Siting Council stated that its finding requiring electric companies to include the technical potential of fuel switching in their demand-side estimates did not constitute a judgment regarding the economic or environmental attractiveness of fuel switching as a resource option for electric companies. Final Decision of the Siting Council on Integrated Resource Management (IRM) Rulemaking, 21 DOMSC 91, 149 (1990) ("1990 Final IRM Decision"). The Siting Council noted that the costs and benefits of fuel switching proposals could vary considerably, and that each such proposal must be evaluated in the context of an electric company's IRM process together with the company's other supply and demand-side options. Id. The Siting Council further noted that only those fuel-switching proposals which are superior to other options would be selected. Id.

Thus, the electric conversion market anticipated by Boston Gas is, at best, a speculative one. This is particularly true in light of the Company's assumptions that: (1) the electric conversion market includes only those conversions occurring as a direct result of electric company-sponsored DSM programs, (2) electric companies will pay for such conversions, and (3) Boston Gas will not provide incentives to electric customers to convert to gas.

The speculative nature of the forecast is further underscored by the fact that Boston Gas is not aware of any electric company plans to voluntarily undertake a fuel-switching program in response to the IRM regulations. The case before the DPU in Docket No. 90-261-A could compel electric utilities to offer cost-effective fuel-switching programs to their customers. However, there is currently no timeframe either for the release of a decision in this case or for the implementation of whatever decision the Department may reach. Consequently, both the timing and the existence of the electric conversion market are in considerable doubt.

In developing its forecast for the electric conversion market, the Company has calculated the technical potential for the market and judgmentally determined market penetration rates. The Siting Council recognizes that, absent specific experience with this new market, developing a forecast requires a heavy reliance on judgment. The Siting Council has previously stated that, for a methodology based largely on judgment to be appropriate, it must be based on appropriate, available information and an understanding of the relevant factors potentially impacting the market being forecasted. 1990 Boston Gas Decision, 19 DOMSC at 372. Here, the Company has relied on the output of its traditional end use forecasting model and an analysis of avoided costs by a respected consultant to determine technical potential, and has identified and estimated the impact of the factors which would contribute to its market penetration rate.

Consequently, for the purposes of this review, the Siting Council finds that the Company has developed a reviewable and appropriate methodology for forecasting the electric conversion market.[67] However, based on our concerns about the existence and the timing of this market, the Siting Council finds that the Company has failed to establish the reliability of the electric conversion forecast for use as an input to the Company's sendout forecast.

In reaching this finding, the Siting Council recognizes that, if it is established, the electric conversion market may contribute significantly to an increase in Boston Gas' sendout. The Siting Council notes that the electric conversion market is the fourth largest growth area forecast by the Company, after the power generation market, traditional end uses, and special projects. It is therefore appropriate for Boston Gas to monitor the development of this market, and to estimate the demand which could result from it. However, until there is some positive indication that electric conversion programs will in fact be implemented, such estimates should not be included in the sendout forecasts used for planning purposes, unless the Company has fully addressed the contingency issues associated with the market (see Section III.F.2.a, below, for a discussion of the role of risk/benefit analysis and contingencies in supply planning).

e. Natural Gas Vehicle Market

i. Description

Boston Gas forecasted that it will add 577 MMcf to its total load from the natural gas vehicle ("NGV") market during the forecast period (Exh. BGC-1, Chart I-A-1, p. 19). The Company stated that the forecast of load additions from NGVs is based on an assessment of the total market potential for NGVs, and the likely gas penetration of the fleet market based on anticipated

67/ The Siting Council notes that this methodology is appropriate only in the absence of specific electric utility implementation plans for electric conversion programs, which would offer the Company a more reliable basis for forecasting this market.

marketing activities, competitive life-cycle direct cost estimates, and environmental benefits (id., p. 19).

In order to estimate the total market potential for NGVs, Boston Gas first identified the number of commercial, government, mass transit and taxi fleets in the Boston Gas service territory (id., Exhibit HO-NV-1, Attachment 1). The Company indicated that it obtained data on commercial fleets from the Massachusetts Census of Transportation,[68] data on government fleets from the regional General Service Administration ("GSA") office, the Commonwealth of Massachusetts Fleet Administrator, and the City of Boston Transportation Department, and data on mass transit and taxi cab fleets from the Massachusetts Bay Transit Authority ("MBTA") and the City of Boston Police Department, Taxi License Division (id.).[69]

For each type of fleet, Boston Gas estimated the average annual miles travelled and average annual miles per gallon (Exh. BGC-1, p. 19). Then, based on the number of vehicles in each fleet type, average annual miles travelled, and gas mileage, the Company calculated total energy demand in MMcfs (id.).

In order to estimate the likely gas penetration rate for each fleet type, Boston Gas first estimated the percentage of vehicles that would switch to an alternative fuel; then it estimated the percentage of these vehicles which were expected to use natural gas as the alternative fuel (id., p.20). The Company estimated that 50 percent of commercial fleets, 40 percent of government fleets, and 80 percent of mass transit would convert to alternative fuels (Exh. HO-NV-1, Attachment 2). For those

68/ Boston Gas considered companies with fleets of at least 6 vehicles as potential marketing targets for commercial NGVs (Exh. HO-NV-1, Attachment 1).

69/ The Company estimated that no taxi cab fleets will switch to alternative fuels in the forecast period. Therefore, no load additions were projected to come from this market (Exh. HO-NV-1, Attachment 2).

vehicles converting to alternative fuels, Boston Gas estimated that 70 percent of commercial fleets, 70 percent of government fleets, and 80 percent of mass transit would switch to natural gas (id.) Boston Gas indicated that all of these estimates were based on "business judgment" (Exh. HO-NV-9). Based on these judgments, the net conversion to natural gas was estimated to be 35 percent for commercial fleets, 28 percent for government fleets, and 64 percent for mass transit (id.). The Company stated that these percentages were adjusted to reflect competition in the natural gas vehicle market (Tr. 2, pp. 11-12).

The Company indicated that the time period used for these estimated conversions to NGVs was 1991-2002, with most load additions occurring after the forecast period (id.). The Company is currently reviewing its forecast methodology for the NGV market and is participating in the New England Gas Association's ("NEGA") NGV Market Potential Study to better identify overall market potential (Exh. HO-NV-1(c)).[70]

Boston Gas described a marketing strategy to promote the use of natural gas as a vehicle fuel which includes demonstration projects with key customers, development of fueling infrastructure, and development of legislative and regulatory support to overcome pre-existing restrictions on NGVs (Exh. HO-NV-2).[71] The Company has opened a fueling station at its Rivermoor facility in West Roxbury, and plans to open other stations on its own property in Malden, Massachusetts, and at the Town of Weston school bus garage in Weston, Massachusetts (id.,

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70/ The planned completion date for the NGV market study is July 1992 (Exh. HO-RR-33). The purpose of this study is to survey decision-makers in each fleet market to gain quantifiable data for projecting NGV load additions (Exh. HO-NV-9).

71/ The Company indicated that a number of regulatory obstacles may present an impediment to the widespread use of natural gas vehicles. As an example, the Company noted that certain agencies interpret their regulations to bar NGVs from using toll roads, tunnels and garages (Exh. HO-RR-6).

Exh. HO-NV-3). The Company indicated that significant investments in infrastructure may be necessary to provide access to the fuel (Exh. HO-NV-3). However, the Company stated that its forecast assumes that fleet owners will make those investments and, therefore, the necessary infrastructure will be in place (Tr. 1, p. 140).

ii. Analysis

The Siting Council notes that Boston Gas is the first gas company in the Commonwealth to present a specific forecast for the NGV market. In doing so, the Company has appropriately attempted to anticipate and prepare for public and private response to new regulatory standards such as the 1990 Clean Air Act Amendments.

In developing its forecast for the natural gas vehicle market, the Company has calculated the technical potential for the market and judgmentally determined market penetration rates. The Siting Council recognizes that, absent specific experience with this new market, developing a forecast requires a heavy reliance on judgment. The Siting Council has previously stated that, for a methodology based largely on judgment to be appropriate, it must be based on appropriate, available information and an understanding of the relevant factors potentially impacting the market being forecasted. 1990 Boston Gas Decision, 19 DOMSC at 372. Here, the Company has not identified the factors which underlie its estimates of market penetration for each type of fleet. Furthermore, it is unclear as to whether and, if so, to what extent, the company's market penetration rates considered potential obstacles to acceptance of NGVs, such as regulatory impediments and lack of adequate infrastructure to fuel the vehicles.

Accordingly, the Siting Council finds that, while the Company has developed a reviewable methodology for forecasting its share of the NGV market, the Company has failed to establish that its forecast is appropriate or reliable.

In reaching this finding, the Siting Council notes that the assessment of technical potential and application of market penetration rates generally constitutes an acceptable methodology for forecasting new markets such as natural gas vehicles. Here, the Siting Council has found that the Company has not adequately supported its determination of market penetration rates. The Siting Council recognizes that the scarcity of information on the NGV market makes it very difficult for Boston Gas to develop an appropriate and reliable forecast at this time; however, we are confident that, as this market develops, the Company will be able to support its market penetration rate estimates. The Siting Council notes that NEGA's NGV Market Potential Study may provide the Company with the data that it needs to support its market penetration rates. Consequently, in order for the Siting Council to approve the Company's NGV forecast in its next filing, the Company must provide supporting analysis for its market penetration rates for each fleet type.

f. Power Generation

i. Description

Boston Gas projected load growth of approximately 14,820 MMcf over the forecast period in the power generation market, which includes both large-scale cogeneration and firm sales to electric utilities (Exh. HO-T-12, Attachment 1). The Company indicated that the forecast reflected sales of 7070 MMcf annually to the West Lynn Creamery cogeneration project ("West Lynn")[72]

72/ Boston Gas presented a signed contract with West Lynn to provide fuel for the project (Exh. HO-RR-18). The Company stated that it expected West Lynn to begin commercial operations in November, 1994, based on the assumption that it would complete its power sales by the summer of 1992 (Exh. HO-LC-9). However, the Company indicated that, to the best of its knowledge, West Lynn has not yet sold any power (id.).

beginning in late 1994, and sales of 7750 MMcf annually to the Boston Edison Company ("BECo")[73] beginning in mid-1992 (id.).[74]

Boston Gas indicated that, since its previous filing with the Siting Council, it has developed an RFP process for determining non-traditional cogeneration market potential, selected a growth target for that market, and identified an interim market for gas supplies until the cogeneration market recovers (Exh. BGC-1, p. 13). The Company indicated that it has twice issued RFPs to potential cogeneration developers, in July, 1989 and in February, 1991 (id., pp. 14-15). The first RFP resulted in gas sales contracts with West Lynn and Boston Thermal; however, the Boston Thermal project was later cancelled by the developer (id., p. 14). The Company stated that only four developers responded to the second RFP, and no contracts resulted from it (id., p. 15). Mr. Gulick indicated that he believes that the non-traditional cogeneration market "is now dormant and likely will remain so for the bulk of the forecast period" (Exh. BGC-3, p. 13).

Boston Gas stated that it had identified 60 MMcf per day on a quasi-firm basis[75] as its growth target for the

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73/ Boston Gas' witness, Christopher Gulick, stated that the Company's forecast of sales to BECo was based on ongoing negotiations, but that no contract had yet been signed (Tr. 3, pp. 109-111). The Company indicated that BECo would use the gas to power existing generating units (Exh. BGC-1, p. 17).

74/ These figures represent an updated forecast of power generation load growth. In its original filing, Boston Gas forecasted load growth of 14,134 MMcf, all added in 1994 (Exh. BGC-1, Chart I-A-1).

75/ The Company defines quasi-firm sales as firm sales for a minimum of 310 days each year, and an average of 330 days over five years (Exh. BGC-1, p. 15).

non-traditional cogeneration market[76] (Exh. BGC-1, p. 15). The Company decided not to acquire incremental capacity to serve the cogeneration market, then used its dispatch model to determine how much gas it could sell over 310 days without violating internal constraints (id., p. 16; Tr. 3, pp. 86-87).[77] Mr. Gulick indicated that 60 MMcf per day represented the upper limit of new sales the Company was willing to make into all quasi-firm markets (Tr. 3, p. 90).

Boston Gas stated that, until the non-traditional cogeneration market recovers, it intends to sell gas on a quasi-firm basis to electric utilities for use in existing power generating units (Exh. BGC-1, p. 17). The Company indicated that it considers this an interim market for its gas, and noted that its average margins are lower in this market than in the cogeneration market (Exh. HO-LC-6; Tr. 3, p. 113). Mr. Gulick stated that the Company's projected sales to BECo, described above, represent the conversion of a current interruptible customer into a quasi-firm customer (Tr. 3, p. 111).

ii. Analysis and Compliance with Order Five

In Order Five of the 1990 Boston Gas Decision, the Siting Council ordered Boston Gas to:

> Provide a detailed methodology for forecasting load additions in the large, non-traditional cogeneration market including a specific analysis of market potential, market growth targets, and marketing programs to achieve such growth targets (19 DOMSC at 464).

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76/ The Company's projected sales to West Lynn and BECo each represent about 25 MMcf per day (Exh. BGC-1, p. 18). Boston Thermal would also have purchased approximately 25 MMcf per day (id., p. 14).

77/ As an example of these "internal constraints," Mr. Gulick cited the Company's planning standard of limiting propane sendout to 15 million gallons per year (Tr. 3, p. 87; Tr. 4, p. 85).

Here, the Company has offered an analysis of market potential based on an RFP process. The Siting Council notes that the RFP process serves a dual purpose: the number of responses provides the Company with a general impression of the strength of the cogeneration market, while the specific responses allow it to identify potential customers. Thus, the RFP serves as both an estimator of market potential and a marketing tool.

The Company has also developed a market growth target which is, simply stated, the amount of gas which the Company has available for sale on a quasi-firm basis given its existing supply portfolio and firm sales commitments. The Siting Council notes that this target reflects the Company's relatively large supply of unsold pipeline gas and the currently depressed state of the cogeneration market. Clearly, Boston Gas undertakes no risks in pursuing this level of sales to the cogeneration market; equally clearly, the Company forgoes no benefits in choosing not to acquire additional supplies to sell into a depressed market. However, as the cogeneration market recovers, the Company will need to develop a more sophisticated approach to balancing the risks and benefits of serving this market.

Accordingly, based on the above, the Siting Council finds that the Company has complied with Order Five of the <u>1990 Boston Gas Decision</u>.

The Siting Council notes that the power generation market, which includes both non-traditional cogeneration and interim sales to electric utilities, makes up 67 percent of Boston Gas's projected load growth over the forecast period. The accuracy of the Company's forecast for this market, therefore, significantly impacts the accuracy of the Company's overall projection of load growth.

Boston Gas has presented a forecast of power generation sales based on expected sales to specific customers. The Siting Council notes that the Company has a signed contract with West Lynn. The timing of the project, however, is uncertain, and, as the Company's experience with Boston Thermal indicates, a signed contract is no guarantee of sales to an unfinanced, unbuilt plant. The sale to BECo would fuel existing, operating equipment; however, the Company has not yet completed contract negotiations for this sale. Thus, Boston Gas cannot be completely confident that either sale will materialize.

Nevertheless, the Siting Council recognizes that the power generation forecast presented by Boston Gas represents the Company's forecast of the most likely level of sales to that market. Accordingly, the Siting Council finds that Boston Gas' forecast of load growth in the power generation market is reviewable, appropriate and reliable for use in developing normal year, design year, and design day sendout forecasts.

In reaching this finding, the Siting Council is aware that either of the two reasonable contingencies discussed above could reduce load growth in this market by half. This would, in turn, reduce total Company load growth over the forecast period by one third. While Boston Gas has appropriately forecasted what it believes is most likely to occur, the Company needs to consider the possible effects of contingencies of this magnitude on its supply planning process. As noted above, in this case Boston Gas takes no risks in forecasting this growth. However, in order for the Siting Council to approve the power generation forecast in its next filing, the Company must submit base and alternative forecasts of load growth in the power generation market, based on reasonable contingencies, and must use these forecasts as a basis for an analysis of the risks and benefits of planning to meet these loads.

g. Special Projects and Fort Devens

In its forecast filing, Boston Gas projected load growth of 1920 MMcf over the forecast period based on sales to two large customers, the Massachusetts Water Resources Authority ("MWRA") sludge treatment plant,[78] and MATEP, a cogeneration plant in the Longwood hospital area of Boston (Exhs. BGC-1, Chart I-A-1, HO-T-11).[79] The Company revised its forecasts during the course of this proceeding to reflect lower expected sendout to the MWRA and MATEP, and new quasi-firm sales to Boston Thermal Company (Exh. BGC-1, "Revisions to Tables"). Finally, Boston Gas projected a load loss of 150 MMcf over the forecast period, based on anticipated downsizing at Fort Devens (Exhs. BGC-1, Chart I-A-1, HO-T-5).[80]

The Siting Council finds that the forecasts for special projects and Fort Devens are reviewable, appropriate, and reliable for use in developing the Company's normal year, design year, and design day sendout forecasts.

h. Conclusions on the Non-Traditional Demand Forecasts

The Siting Council has found that Boston Gas' forecasts for the power generation market, the small-scale cogeneration market and special projects and Fort Devens are reviewable, appropriate, and reliable for use in developing normal year, design year and design day sendout forecasts. The Siting Council has also found that the Company's gas-fired air conditioning and

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78/ Boston Gas indicated that the MWRA signed a contract for firm gas service to the sludge treatment facility in May, 1990 (Exh. HO-T-11.) The Company noted that, since then, the timing of the MWRA project has changed, and the MWRA has decided to explore other long-term options for gas purchasing (id.).

79/ Boston Gas supplied a copy of its contract with Cogeneration Management Company for service to the MATEP project, and indicated that the facility began to take gas under the agreement in mid-October, 1991 (Exh. HO-T-11).

80/ The Company indicated that, based on discussions with Field Marketing personnel handling the Fort Devens account, it projected that load at Fort Devens would decrease by 10 percent of actual 1990 load, or approximately 37 MMcf, each year for five years (Exh. HO-T-5).

desiccant dehumidification forecasts are reviewable and appropriate, but made no finding on their reliability for use in developing normal year, design year, and design day sendout forecasts. Further, the Siting Council has found that the Company's electric conversion forecast is reviewable and appropriate, but that the Company has failed to establish its reliability for use in developing normal year, design year and design day sendout forecasts. Finally, the Siting Council has found that the Company's NGV forecast is reviewable, but that the Company has failed to establish that it is appropriate or reliable for use in developing normal year, design year and design day sendout forecasts.

The Siting Council notes that the power generation forecast, which we have found to be reviewable, appropriate, and reliable, constitutes approximately 80 percent of the total of non-traditional demand forecasts. Consequently, on balance, the Siting Council finds that Boston Gas' forecasts of demand for natural gas in non-traditional markets is reviewable, appropriate, and reliable for use in developing normal year, design year and design day sendout forecasts.

### 3. Regression Equation

#### a. Description

Boston Gas stated that it used regression analysis to normalize daily temperature sensitive sendout (Exh. BGC-1, p. 29). The Company used actual sendout and weather data from April, 1990 through March, 1991, to develop weather-normalized estimates of total firm sendout for existing customers (Exh. HO-RR-1; Tr. 3, p. 9). The Company indicated that it developed its basic regression model several years ago, and that it reviews and evaluates the model specification at least annually, based on discussions with staff, including dispatchers (Tr. 3, pp. 8, 39).

The Company noted that, since the previous filing, it has changed the dependent variable used in its model from estimated temperature-sensitive sendout to actual total firm sendout (Exhs. HO-RE-2, HO-RE-3). The Company explained that this change allowed it to include 365 days of data in its analysis; previously, days whose DD value was zero or whose estimated temperature-sensitive sendout was less than zero were excluded from the analysis, leaving only about 260 days worth of data (Exh. HO-RE-3). The Company also noted that the new specification improves the regression coefficient estimates, since the regression equation intercept is not forced to zero (Exh. HO-RE-2).

Boston Gas stated that it considered revising the independent variables used in the regression equation, but did not do so (Exh. HO-RE-12). The Company noted, however, that it intends to update these variables based on the results of the load research study which it is currently conducting (Exh. BGC-1, p. 33). The Company indicated that the variables used in the regression equation included: DD level; dichotomous DD level/month variables for the months of October through May;[81] dichotomous DD level/temperature range variables for five temperature ranges; two variables which reflected customer response to cold days preceded by one and two cold days, respectively; and a weekday/weekend variable (Exh. BGC-1,

81/ The Company indicated that the dichotomous DD/month variables were intended to model variations in space heating consumption patterns as heating was brought on-line and off-line throughout the heating season (Exh. BGC-1, p. 30; Exh. HO-RE-6). The Company stated that it did not include DD/month variables for June through September because space heating load in those months was included in the baseload (Exh. HO-RR-5). Ms. Smith also stated that such variables were unlikely to be statistically significant, since the low heating load during these months would limit the number of DD observations (Tr. 3, p. 42).

Chart I-B-23). All were statistically significant except the temperature range variables (id.).[82]

The Company stated that the temperature range variables were intended to model changes in equipment efficiency and customer behavior at various temperatures (id., p. 31; Tr. 3, p. 43). The Company indicated that it included these variables in the regression analysis, despite their lack of statistical significance, because there were theoretical reasons to expect that these variables would affect sendout, and because they had proved significant in the past (Exh. HO-RE-6; Tr. 3, p. 45).[83] The Company's witness, Amy Smith, noted that the coefficients on these variables were quite small, and that the variables "certainly don't do any harm" (Tr. 3, pp. 47, 49). Ms. Smith noted that the Company's load research study may validate the effects which these variables describe (id., p. 45).

b. Analysis

In the 1990 Boston Gas Decision, the Siting Council found that the Company's analysis of existing aggregate firm sendout was a reviewable, appropriate, and reliable input for its sendout forecasts (19 DOMSC at 380). However, the Siting Council expressed concern about the process by which the Company reviewed and enhanced its regression equation, and expected that the Company would develop a more formalized and sophisticated review process. Id. at 379.

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82/ Statistical significance is a measure of the likelihood that an independent variable has an impact on the value of the dependant variable. A variable is statistically significant at the 95 percent level if the absolute value of its T-statistic is 1.96 or greater. The T-statistic for the temperature range variables ranged from -0.21 to 0.56 (Exh. BGC-1, Chart I-B-23).

83/ Boston Gas indicated that temperature range variables were statistically significant in 1984/85, 1985/86, and 1986/87 (Exh. HO-RR-17).

The Siting Council notes that, for this filing, Boston Gas has changed its dependant variable from estimated temperature-sensitive sendout to actual total firm sendout. This change clearly enhances the regression model, and reflects the Company's continuing efforts to improve its sendout forecasting.

However, the Company's review of its regression model was not comprehensive enough either to exclude statistically insignificant variables or to investigate the inclusion of possibly significant variables. The extremely low T-statistics of the temperature range variables indicate that these variables do not contribute to the explanatory power of the regression equation, and that their inclusion may bias the sendout predictions. Similarly, the Company failed to evaluate the inclusion of DD/month variables for the months of June through September, even though it had moved from an independent variable which effectively excluded summer months from analysis to one which included them.

On balance, however, the Company's continuing efforts to improve its regression model, as evidenced by its revision of the dependant variable, outweigh these criticisms. Consequently, the Siting Council finds that the Company's analysis of existing aggregate firm sendout is reviewable, appropriate, and reliable as an input to its normal year, design year, and design day sendout forecasts. The Siting Council notes that Boston Gas is currently conducting a load research study which should provide it with further insights into its sendout patterns and encourages the Company to use this data as a basis for a thorough evaluation of its regression model.

### 4. Cold Snap Factor

#### a. Description

Boston Gas indicated that, in modelling design year sendout, it increased the sendout predicted by the regression equation by a "cold snap factor" of 4 percent for days of 40 DD or more (Exhs. HO-RE-7, BGC-1, p. 31). The Company stated that it based this adjustment on its observation that, in the near-design winter of 1980/81 and in January 1982, the regression model consistently underpredicted sendout on very cold days by two to six percent (Exh. HO-RE-7).

The Company stated that the cold snap factor was intended to model non-linear customer response to extreme cold (Exh. BGC-1, pp. 31-32). The Company indicated that it analyzed metering data for December, 1988 through April, 1989, and found no obvious non-linear response to cold weather (id., p. 32). The Company also compared actual and predicted sendout on days of 40 DD or more in 1989/90 and 1990/91, but found no pattern of sendout greater than the model predictions (id.). The Company noted that none of the winters analyzed approached design conditions, when the non-linear behavior would be expected to occur (id.). The Company stated that it had not considered other ways of modeling non-linear response to cold weather because it had no recent near-design weather to use for such an analysis (Exh. HO-RE-9). The Company indicated that the load research study might provide some insight into customer behavior in design-like weather (id., p. 33).

b. Analysis

In the 1990 Boston Gas Decision, the Siting Council expressed its concern that the Company had not considered more statistically justifiable approaches to modelling customer behavior in near-design weather (19 DOMSC at 379-380). In this filing, the Company has provided analyses which fail to document the behavior which the cold snap factor is intended to model. However, as the Company has noted, none of the three years analyzed contained an extensive period of near-design weather. The Siting Council recognizes that, under these circumstances, it is impractical for the Company to evaluate other methods of modelling customer behavior in near-design weather. Therefore, the Siting Council finds that the continued use of the cold snap factor in design forecasts is acceptable. However, the Siting Council expects the Company to develop a more statistically justifiable model for customer behavior in near-design conditions when the necessary data becomes available.

5. Normal and Design Year Sendout Forecasts

a. Description

Boston Gas stated that its forecasts of total Company firm sendout were generated by the Company's gas balance model (Tr. 3, p. 162). The Company stated that the inputs to the gas balance model include the regression equation, normal and design year databases, forecasts of load additions from its demand models, and forecasts of requirements of large-volume customers (id., p. 7).[84] The Company indicated that it forecast normal year sendout for each day of the forecast period as the sum of existing requirements and cumulative net load additions (id., p. 11). The Company stated that existing requirements were determined using the regression equation and the DD level for that day from the normal year database and that baseload additions were calculated as 1/365 of cumulative net baseload additions (id., pp. 14-15). Boston Gas stated that heat-sensitive additions were calculated as the product of cumulative net heat-sensitive additions and the percentage of annual heat-sensitive load which that day received in the normal base year (id.). Sendout forecasts for individual days were

84/ Boston Gas indicated that its large-volume customers are the Town of Braintree, MATEP, Boston Thermal, BECo, and West Lynn (Exh. BGC-10, pp. 27-31). The Company indicated that sendout to these customers was forecast based on minimum contract requirements, and provided graphs showing specific assumptions regarding sendout to each customer (id.; Tr. 3, p. 12). For example, the Company assumed that it would provide 12 MMcf/day to the Town of Braintree between March 4 and November 28 of each year of the forecast period (Exh. BGC-10, p. 27).

summed to provide monthly and annual sendout forecasts (id., p. 19).

The Company indicated that total firm design year sendout was forecast in the same manner, with the following exceptions: (1) the Company used the design year database instead of the normal year database to calculate existing requirements; (2) the Company used the cold snap factor when calculating existing requirements; (3) the Company used gross, rather than net, load additions for the forecast year; and (4) the Company multiplied heat-sensitive load additions by 1.1 to account for the effects of design weather (id., pp. 11-12, 14, 15).

Boston Gas also provided tables showing normal and design year sendout by customer class (Exh. BGC-1, Tables G-1 through G-4(D)).[85] The Company stated that the gas balance model was not capable of breaking down sendout by customer class (Tr. 3, p. 162). Instead, the Company used actual base year sales by customer class for existing demand, and added net cumulative load additions for each class to determine normal year sendout forecasts (id., p. 163). Design year sendout was forecast using gross load additions for the forecast year, and load additions were multiplied by 1.1 to account for the effect of design year weather (id., Exh. HO-T-2).

b. Analysis

In the 1990 Boston Gas Decision, the Siting Council found that normal and design year sendout forecasts developed using this methodology were reviewable, appropriate, and reliable (19 DOMSC at 382). In previous sections of this Decision, the Siting Council has found that (1) the Company's normal year and

85/ These customer classes were: residential with gas heating, residential without gas heating, commercial, industrial, Wakefield, quasi-firm, interruptible, sales for resale, and company use and unaccounted for (Exh. BGC-1, Tables G-1 through G-4(D)).

design year standards are appropriate and reliable; (2) the Company's forecasts of gross and net load additions generated by its traditional end use model are appropriate and minimally reliable for use in developing normal year, design year, and design day sendout forecasts; (3) the Company's forecasts of load additions from nontraditional end uses are appropriate and reliable for use in developing normal year, design year, and design day sendout forecasts; and (4) the Company's analysis of existing aggregate firm sendout is appropriate and reliable as an input to its normal year, design year, and design day sendout forecasts. Consequently, the Siting Council finds that the Company's normal year and design year sendout forecasts are reviewable, appropriate, and minimally reliable.

The Siting Council has noted above that the power generation forecast, which contains substantial uncertainties, constitutes nearly two-thirds of the Company's projected load growth over the forecast period. The full weight of this uncertainty, and of the uncertainty pertaining to other load growth forecasts, carries over into the forecasts of normal and design year sendout. Consequently, in order for the Siting Council to approve the Company's normal and design year sendout forecasts in its next forecast, the Company must present a set of alternative sendout forecasts when dealing with uncertainties of this magnitude.

6. Design Day Sendout Forecast

Boston Gas indicated that it used the gas balance model to develop sendout forecasts for a design day of 73 DD. The Company assumed that its design day occurred in January, following two consecutive cold days (Exh. BGC-10, p. 33; Tr. 3, p. 14). The Siting Council has found, in Section II.C.4.b, above, that the Company's design day standard is reviewable, appropriate, and minimally reliable. Further, the Siting Council has found that the Company's use of the gas balance model produced reviewable, appropriate, and minimally reliable normal year and design year forecasts. The Siting Council finds that the use of this model to develop the design day forecast is also reviewable and appropriate. Accordingly, the Siting Council finds that the Company's forecast of design day sendout is reviewable, appropriate, and minimally reliable.

We note that, in preparing the design day sendout forecast, the Company assumes that its quasi-firm and interruptible customers, including both power generation customers, are off-line (Tr. 3, p. 16). The uncertainty which the Siting Council has found in the normal and design year sendout forecasts therefore does not affect the design day sendout forecast.

E. Conclusions on the Sendout Forecast

In previous sections of this Decision, the Siting Council has found that (1) the Company's planning standards are reviewable, appropriate, and reliable; (2) the Company's normal year and design year sendout forecasts are reviewable, appropriate, and minimally reliable, and (3) the Company's design day sendout forecast is reviewable, appropriate, and minimally reliable.

Accordingly, the Siting Council hereby APPROVES the 1991 sendout forecast of the Boston Gas Company.

In approving this forecast, the Siting Council recognizes the Company's significant progress since the last decision in developing new standards and forecasting new markets. The Company's cost/benefit analyses of its planning standards represent a new level of sophistication for gas company planning. Similarly, the Company's efforts to develop forecast methodologies for new markets are in the forefront of gas company planning.

However, in the rapidly evolving market for natural gas, a single point forecast may no longer be sufficient to represent the uncertainty facing gas companies, especially those which aggressively target new markets. Therefore, in the future, Boston Gas, and other large gas companies, should develop techniques for evaluating the uncertainty in their sendout forecasts, and the effects this uncertainty may have on their supply planning process. Boston Gas has indicated that it is developing supply planning techniques which will allow it to evaluate supplies over a range of future scenarios (see Section III.D.2.a, below). The Siting Council encourages Boston Gas to continue to develop these new techniques.

## III. ANALYSIS OF THE SUPPLY PLAN

### A. Standard of Review

The Siting Council is required 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. In fulfilling this mandate, the Siting Council reviews a gas company's supply planning process and the two major aspects of every utility's supply plan -- adequacy and cost.[86] 1991 Colonial Gas Decision, 23 DOMSC at 388; 1990 Boston Gas Decision, 19 DOMSC at 384; 1990 Berkshire Decision (Phase 1), 19 DOMSC at 281; 1989 Bay State Decision, 19 DOMSC at 179; 1989 Fitchburg Decision, 19 DOMSC at 99; 1988 ComGas Decision, 17 DOMSC at 108; 1987 Bay State Decision, 16 DOMSC at 308; 1987 Berkshire Decision, 16 DOMSC at 71; Fall River Gas Company, 15 DOMSC 97, 111 ("1986 Fall River Decision"); 1986 Holyoke Decision 15 DOMSC at 27; 1986 Berkshire Decision, 14 DOMSC at 128.

The Siting Council reviews a gas company's five-year supply plan to determine whether that plan is adequate to meet projected normal year, design year, design day, and cold-snap firm sendout requirements (see Section III.C, below).[87] In order to establish adequacy, a gas company must demonstrate that it has an identified set of resources which meet its projected sendout

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86/ The Siting Council's enabling statute also directs it to balance cost considerations with environmental impacts in ensuring that the Commonwealth has a necessary supply of energy. See Section III.D.2.b.ii, below.

87/ The Siting Council's review of reliability, another necessary element of a gas company's supply plan, is included within the Siting Council's consideration of adequacy. See: 1991 Colonial Gas Decision, 23 DOMSC at 389, n. 23; 1990 Boston Gas Decision, 19 DOMSC at 385, n. 25; 1990 Berkshire Decision (Phase 1), 19 DOMSC at 282, n. 16; 1989 Bay State Decision, 19 DOMSC at 180, n. 19; 1989 Fitchburg Decision, 19 DOMSC at 100; 1988 ComGas Decision, 17 DOMSC at 109; 1987 Bay State Decision, 16 DOMSC at 309; 1987 Berkshire Decision, 16 DOMSC at 72; 1987 Boston Gas Decision, 16 DOMSC at 214.

under a reasonable range of contingencies. If a company cannot establish that it has an identified set of resources which meet sendout requirements under a reasonable range of contingencies, the company must then demonstrate that it has an action plan which meets projected sendout in the event that the identified resources will not be available when expected. 1991 Colonial Gas Decision, 23 DOMSC at 389; 1990 Boston Gas Decision, 19 DOMSC at 385; 1990 Berkshire Decision Phase 1), 19 DOMSC at 282; 1989 Bay State Decision, 19 DOMSC at 180; 1989 Fitchburg Decision, 19 DOMSC at 100; 1988 ComGas Decision, 17 DOMSC at 108; 1987 Bay State Decision, 16 DOMSC at 308; 1987 Berkshire Decision, 16 DOMSC at 71.

In its review of a gas company's supply plan, the Siting Council reviews a company's overall supply planning process (see Section III.D below). An appropriate supply planning process is essential to the development of an adequate, low-cost, and low-environmental impact resource plan. Pursuant to this standard, a gas company must establish that its supply planning process enables it to (1) identify and evaluate a full range of supply options, and (2) compare all options -- including C&LM -- on an equal footing. 1991 Colonial Gas Decision, 23 DOMSC at 388; 1990 Boston Gas Decision, 19 DOMSC at 384; 1990 Berkshire Decision (Phase 1), 19 DOMSC at 281; 1989 Bay State Decision, 19 DOMSC at 179; 1989 Fitchburg Decision, 19 DOMSC at 99; 1988 Commonwealth Gas Decision, 17 DOMSC at 138-39; 1987 Bay State Decision, 16 DOMSC at 323; 1987 Berkshire Decision, 16 DOMSC at 85; 1986 Fall River Decision, 15 DOMSC at 115.[88]

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88/ In 1986, G.L. c. 164, §69J was amended to require a utility company to demonstrate that its long-range forecast "include[s] an adequate consideration of conservation and load management." Initially, the Siting Council reviewed gas C&LM efforts in terms of cost minimization issues. In the 1988 Commonwealth Gas Decision, 17 DOMSC at 122-126, the Siting Council expanded its review to require a gas company to demonstrate that it has reasonably considered C&LM programs as resource options to help ensure that it has adequate supplies to

Finally, the Siting Council reviews whether a gas company's five-year supply plan minimizes cost (see Section III.E, below). A least-cost supply plan is one that minimizes costs subject to trade-offs with adequacy and environmental impact. 1991 Colonial Gas Decision, 23 DOMSC at 390; 1990 Boston Gas Decision, 19 DOMSC at 49-50; 1990 Berkshire Decision (Phase 1), 19 DOMSC at 282; 1989 Bay State Decision, 19 DOMSC at 180; 1989 Fitchburg Decision, 19 DOMSC at 100; 1988 ComGas Decision, 17 DOMSC at 109; 1987 Bay State Decision, 16 DOMSC at 309; 1987 Berkshire Decision, 16 DOMSC at 72; Massachusetts Electric Company/New England Power Company, 18 DOMSC 295, 337 ("1989 MECo/NEPCo Decision"). Here, a gas company must establish that application of its supply planning process has resulted in the addition of resource options that contribute to a least-cost plan.

B. Base Case Supply Plan

In this section the Siting Council reviews the Company's supply plan and identifies elements which represent potential contingencies affecting adequacy of supply or which potentially impact the cost of the supply plan. The Siting Council then reviews the adequacy of the Company's supply plan in Section III.C, the Company's supply planning process in Section III.D, and the cost of the Company's supply plan in Section III.E, below.

1. Pipeline Supplies

Boston Gas receives pipeline gas from Algonquin and Tennessee (Exh. BGC-1, p. 44). Boston Gas also purchases gas

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meet projected sendout requirements.

directly from TETCO and the Boundary Gas consortium (id., pp. 51-53).[89]

Algonquin provides the Company with firm sales service under rates F-1, F-2, F-3, and WS-1 (Exh. BGC-1, pp. 46-50, Table G-24, p. 1). Both the Algonquin F-2 and F-3 supply contracts are due to expire on November 1, 1992, although the transportation contracts under these rates will not expire until well beyond the forecast period (Exh. BGC-1, pp. 48-50, Table G-24, p. 1). The Company stated that it was having discussions with Algonquin and National Fuel Gas regarding conversion to firm transportation service for both of these supplies (id., pp. 49-50).

Boston Gas' contract for Algonquin's WS-1 service, which is a firm winter sales service with a storage component, has expired (id., p. 55). The Company's rights to this service continue pending FERC certification of TETCO's and Algonquin's proposed contract restructuring (id.).[90]

Boston Gas receives firm sales service from Tennessee under rate CD-6 (id., pp. 50-51, Table G-24, p. 3). Tennessee also provides Boston Gas with firm transportation of volumes from Boundary Gas (id., p. 53, Table G-24, p. 4). This supply is

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89/ On April 8, 1992, the Federal Energy Regulatory Commission ("FERC") issued Order No. 636, known as the "Restructuring Rule". FERC Order 636 (April 8, 1992). Boston Gas stated that these regulations are expected to result in a complete restructuring of the gas pipeline industry (Exh. HO-PL-27). Boston Gas indicated that FERC expects all gas pipeline companies to file restructuring programs within two years of adoption of the rule, and the Company expects to "have the opportunity" to restructure all of its services during this two year period (id.).

90/ Boston Gas stated that it anticipates that FERC will certify the restructured services some time in 1992, probably in conjunction with the TETCO settlement (Exh. HO-FS-5). Boston Gas indicated that Algonquin proposes that three new services replace the WS-1 service: TETCO storage service, firm transportation from storage to Algonquin on TETCO's system, and firm transportation from TETCO to Boston Gas on Algonquin's system (Exhs. HO-FS-5, BGC-1, pp. 55-56).

transported by TransCanada Pipeline Company from Western Canada to the international border at Niagara Falls, New York, from which point Tennessee provides firm transportation to the city gate (id.).

In April, 1992 the FERC approved a major settlement concerning Tennessee restructuring. Tennessee Gas Pipeline, Docket Nos. RP86-119-000, et al. (April 8, 1992). Commonly referred to as the "Cosmic Settlement", the FERC approval will allow Tennessee customers to convert up to 100 percent of their Tennessee CD-6 gas supply service to firm transportation capacity and purchase gas directly from their own suppliers (Exh. BGC-11, p. 2). The Company stated that it has chosen to "unbundle" its current CD-6 service, and to convert 47,000 MMbtu per day of this service to firm transportation (id.).[91] The Company stated that it is currently negotiating direct purchase agreements with a number of gas suppliers to replace the converted CD-6 volumes, and has recently signed contracts with four of these suppliers (Exhs. HO-PL-28, HO-RR-28). The Siting Council reviews the least cost nature of the Company's response to the Tennessee restructuring in Section III.E.2.b below.

In December 1990, the Company began receiving volumes from TETCO under its PennEast CDS service (Exh. BGC-1, p. 52). The Company later began receiving an additional 10,000 Mcf per day, for a total MDQ of 39,109 Mcf per day (id., Tr. 4, p. 74), of which 20,501 Mcf is delivered to the Company on a firm basis, while 18,608 Mcf is delivered on a firm basis to Algonquin and then on an interruptible basis to the Company's city gate (Exh. BGC-1, p. 52).

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91/ The Company stated that unbundling will reduce its peak day MDQ on the sales service from 136,000 Mcf to 94,312 Mcf, the average MDQ (Tr. 5, p. 91). Boston Gas has stated that it would offset the reduction in the peak day MDQ with a storage service in upstate New York and Pennsylvania with a MDQ of 41,687 Mcf, and an annual storage quantity of 5,406,507 Mcf (id., pp. 91-92).

Boston Gas also has executed contracts with Esso and ANE for two new supply/transportation projects to obtain natural gas from Alberta, Canada (id., p. 65; Exh. BGC-3, p. 10). The Esso contract was approved by the DPU in Boston Gas Company, DPU 89-180 (1990). The ANE contract is currently before the DPU as part of this joint proceeding. The Siting Council evaluates whether the ANE volumes contribute to a least-cost supply plan in Section III.E.2.a, below.

Boston Gas stated that the Esso volumes are scheduled to begin flowing on a firm basis by November 1, 1992, but could potentially be available earlier on an interruptible basis (Tr. 4, p. 94). Boston Gas is entitled to take an MDQ of 34,405 Mcf per day from this supply (Exh. BGC-1, p. 66). The Company stated that the Esso volumes are delivered from TransCanada Pipeline to Iroquois to Tennessee and Algonquin for delivery to the city gate.[92]

The Company stated that the ANE volumes began flowing on December 1, 1991 (Tr. 5, p. 137).[93] The ANE supply is delivered

92/ Boston Gas will have the ability to take between zero and 100 percent of the Esso MDQ on any given day, subject to a producer-initiated annual contract quantity reduction ("ACQ") if the Company fails to take a minimum of 75 percent of the MDQs over a rolling 730-day period and a quarterly gas inventory charge ("GIC") when quarterly takes are less than 75 percent of the sum of the MDQs (Exh. BGC-1, p. 67).

93/ The Company originally contracted to receive 17 MMcf per day of the ANE volumes (Exh. HO-FS-4). In July 1991 the Company entered into precedent agreements contemplating reallocations of the ANE volumes to Colonial Gas Company and Commonwealth Gas Company in the amounts of 4 MMcf per day and 4.5 MMcf per day, respectively (id., Attachments 1 and 2). Boston Gas' ANE volumes have, therefore, been reduced to 8.6 MMcf per day (Exh. HO-FS-4, Tr. 5, p. 137).

from TransCanada to Iroquois to Tennessee for delivery to the city gate.[94]

2. Storage Facilities and Services

Boston Gas sends gas to underground storage during the non-heating season and the gas is returned for sendout during the heating season (Exh. BGC-1, p. 54). Algonquin provides Boston Gas with approximately 4459 MMcf of storage service and return transportation under rates STB and SS-III (id., pp. 56-58). The contract withdrawal period for these two storage services is between November 1 and March 31 (id., p. 57). Boston Gas has stated that as a result of a recent settlement, it has the right to inject up to 50 percent third-party gas to these storage services, the remainder being the Algonquin F-1 or TETCO CD-1 volumes (id.). Pending FERC approval of a proposed Algonquin contract restructuring, Boston Gas expects to obtain the right to inject 100 percent third party gas into storage (id., pp. 57-58).

Tennessee provides transportation to Boston Gas from three storage services: (1) Consolidated Gas Supply Corporation ("Consolidated") under rate GSS, with associated firm return transportation via Tennessee under rate FSST-NE; (2) Honeoye Storage Corporation ("Honeoye") under rate SS-NY, with associated return transportation via Tennessee under rates FSST-NE (firm) and ISST-NE (interruptible); and (3) Penn-York Energy Corporation ("Penn-York") under rate SS-1, with associated return transportation via Tennessee under rates FSST-NE and ISST-NE (id., p. 59, Table G-24, pp. 3-4). The storage provided under these three contracts totals 1917 MMcf (Exh. HO-BGC-1, p. 59). The Honeoye and Penn-York contracts expire within the forecast

94/ Boston Gas will have the ability to take between zero and 100 percent of ANE MDQ on any given day subject to a producer-initiated ACQ reduction if the Company fails to take a minimum of 60 percent of ACQ in any given year and does not make up the deficiency volume within the next year (Exh. BGC-1, p. 66).

period, as do all the transportation contracts (id., Table G-24, pp. 3-4). The Company stated that it plans to renew its contract with Honeoye, but may not renew the Penn-York contract due to gas migration problems in that storage field (Exh. HO-FS-7). Boston Gas stated that all of the transportation contracts for these storage facilities will be renewed (id.).[95]

Boston Gas is currently negotiating an agreement for 1,203 MMcf of underground storage in the second phase of the Steuben Storage Project, which is expected to be available in the 1993-94 heating season (Exhs. HO-FS-6, BGC-1, pp. 65, 67).[96] Boston Gas stated that FERC certification for phase two of the Steuben project will be sought following contract negotiations with customers (Exh. BGC-1, pp. 67-68). Boston Gas has indicated that transportation from Steuben storage to the city gate will be firm on Consolidated and interruptible on Tennessee (id., p. 67). The Company stated that, initially, it does not intend to rely on the Steuben service to meet peak day sendout requirements, since it is not likely to be available on peak days (id., p. 68; Exh. HO-IS-6(c)). However, the Company indicated that the interruptible transportation could be firmed up at such time as Steuben volumes are required for peak day needs (id., p. 68; Exh. HO-IS-6(c)).

### 3. Supplemental Supplies and Facilities

#### a. LNG

Boston Gas and Mass LNG operate LNG vaporization and storage facilities at Commercial Point in the Dorchester section of Boston, and in Lynn and Salem (Exh. BGC-1, pp. 62-63). The

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95/ The Company states that, in the event the Penn-York storage contract is not renewed, the transportation will be used to move gas from an alternative storage service (Exh. HO-FS-7).

96/ Mr. Gulick noted that the Steuben volumes could be a possible replacement for the Penn-York volumes (Tr. 4, p. 129).

combined storage capacity of these three facilities is 4,140 MMcf (id.). The combined daily vaporization capacity of these facilities is 291.4 MMcf (id.).[97] The Company also provides for daily standby capacity at the Salem and Commercial Point facilities in the event of an equipment malfunction. This standby capacity, which represents the equivalent of one vaporizer at these facilities, is 77.5 MMcf per day (id., p. 63).[98] The Company stated that for peak day operation it also has two small LNG vaporization facilities in Leominster and Webster (id.). The combined vaporization capacity of these two facilities is 4.8 MMcf per day (id.).

Pursuant to a June 1988 settlement, Boston Gas and DOMAC entered into a number of agreements, including a storage service agreement, a liquid purchase agreement, a firm transportation agreement, and a boil-off service agreement under which Boston Gas purchases all of the LNG boil-off in DOMAC's Everett tanks, up to 3,300 Mcf per day, at Boston Gas' daily avoided cost of pipeline gas (id., pp. 60-61).

The Company also stated that it retains rights to store 400 MMcf of LNG at Algonquin's LNG facility in Providence, Rhode

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97/ The Company has decided to remove from service its liquefaction facility at Lynn, which has a daily liquefaction capacity of 7.4 MMcf. Boston Gas stated that the LNG storage and vaporization capacity at Lynn is not affected by this decision. The Company did not rely on the availability of the Lynn liquefaction facility in its planning process (Exh. BGC-11, p. 4).

98/ Boston Gas has decided to take one of the Dorchester LNG tanks out of service in the summer of 1992 due to the expense of making necessary tank improvements, and the Company's reduced reliance on liquid supplies (Tr. 4, pp. 113-115). Boston Gas stated that the loss of this tank will reduce overall storage capacity by approximately one Bcf, but vaporization capacity will not change (id., p. 152). According to Boston Gas, the Company's ability to meet design-year sendout requirements in the forecast period will not be affected by the loss of this LNG tank since its storage capacity is not included in the Company's supply planning (id., p. 153; Tr. 5, p. 126).

Island (id., pp. 61-62). Boston Gas noted that the contract for this service expired on May 31, 1992, and that the Company indicated to Algonquin its intention to renew the contract for a two-year period (id., Exh. HO-FS-9). The Company also noted that, while there is vaporization equipment on-site at the facility, no vaporization capacity is currently available (Exh. BGC-1, pp. 61-62).

b. Propane

Boston Gas operates a major propane-air facility at its Everett location, in addition to ten satellite facilities throughout its operating area (id., p. 64). These facilities have a total maximum daily operating capacity of 67,300 Mcf and a combined total storage capacity of 167,600 Mcf (id.).

The Company also operates a synthetic natural gas ("SNG") production facility in Everett, with a daily maximum operating capacity of 40,000 Mcf per day. The Company stated that this facility will be shut down by mid-1992 because the technology is outdated and the plant is expensive to run when compared to other available supplies (Exh. BGC-11, p. 4).

Boston Gas stated that it is currently reviewing its propane facilities to determine the costs of maintaining, upgrading, consolidating and/or dismantling these facilities (id., pp. 4-5, Exh. HO-FS-11). The Company stated that it anticipates closing one or more propane-air plants and consolidating some others, but does not expect to significantly reduce propane-air production capability (Exhs. HO-FS-11, BGC-11, p. 5).

4. Conservation and Load Management

Boston Gas is currently implementing residential conservation programs approved by the DPU in Boston Gas Company, DPU 90-17/18/55 ("DPU 90-55") (Exh. BGC-1, p. 70). The DPU also recently approved the Company's proposed conservation programs for the commercial/industrial sector in Boston Gas Company, DPU 90-320 (1992) ("DPU 90-320"). The Company's proposed supplemental residential conservation programs are currently under review by the DPU in Docket DPU 91-29 (Exh. BGC-1, p. 70).

The Company's demand-side management ("DSM") portfolio includes the following programs:

> (1) Residential Water Heating Program -- This program provides for the installation of domestic hot water tank wraps, low-flow showerheads, faucet aerators, temperature turn down, and domestic hot water pipe insulation in eligible residences. The Company has targeted approximately 106,000 of its residential customers for this program, and projected annualized savings of 125 MMcf over a 22-month "ramp-up" period ending April 1992, and a total of 462 MMcf over a five-year implementation period ending in 1995 (id.; Tr. 5, p. 170).
>
> (2) Residential Attic Insulation Program -- This program provides for subsidies of 50 to 100 percent of the cost of insulating attic spaces in customers' homes (id.). Approximately 33,000 of the Company's residential customers are targeted for this program, which is estimated to bring annualized savings of 39 MMcf by the end of the ramp-up period, and a total of 319 MMcf by 1995, the end of the five-year implementation period (Exh. BGC-1, pp. 70-71; Tr. 5, p. 170).
>
> (3) Residential Home Heating Controls Program -- This program offers rebates of 50 to 100 percent for the installation of clock thermostats, boiler resets and thermal vent dampers in eligible homes (Exh. BGC-1, p. 71). The Company has targeted 46,000 customers for this program, which is expected to bring annualized savings of 138 MMcf by the end of the ramp-up period, and a total of 854 MMcf by 1995, the end of the five-year implementation period (id.).
>
> (4) Multifamily Energy Savings Plan -- This program provides multi-family residential customers with a 50 percent subsidy for all cost-effective thermal envelope and mechanical efficiency measures (id.). Approximately 13,600 dwelling units are targeted for this program, which is expected to bring annualized savings of 150 MMcf during the ramp-up period and a total of 569 MMcf by 1995, the end of the five-year implementation period (id., pp. 71-72; Tr. 5, p. 170).

(5) Residential High-Use Customer Program -- This proposed program, currently before the DPU in DPU 91-29, would target approximately 7,300 residential customers whose space heating load is at least 50 percent higher than that of the typical residential customer, providing energy audits and all cost-effective DSM to those targeted customers (Exh. BGC-1, p. 72). The program is expected to bring annualized savings of 189 MMcf by the end of the program's ramp-up period, and a total of 691 MMcf by the end of the four-year implementation period (id.).

(6) Residential High-Efficiency Furnace Replacement Program -- This proposed program, also before the DPU in DPU 91-29, would provide financial incentives to customers whose equipment is at the end of its useful life to replace their furnaces with high-efficiency equipment (id.) Targeted toward 10,700 residential customers, this program is estimated to bring annualized savings of 19 MMcf by the end of the program's ramp-up period, and a total of 69 MMcf by the end of the four-year implementation period (id.).

(7) Commercial and Industrial Program -- This program, approved in DPU 90-320, will provide technical and financial assistance as well as installation and contractor arranging services to encourage the implementation of all cost-effective conservation measures (id., p. 73). The program is targeted toward 3,800 commercial customers and 320 industrial customers (id.). The Company estimates that annualized savings from these programs will be 119 MMcf by the end of the ramp-up period, and a total of 986 MMcf by the end of the four-year implementation period (id.).

The Company did not include any energy savings from these programs as supply resources in its base case supply plan (id., p. 74, Tables G-22D (Revised), G-22N (Revised), G-23 (Revised), G-24). The Company's compliance with the Siting Council's order concerning the inclusion of conservation resources in the base case supply plan is reviewed in Section III.F.4, below.

C. Adequacy of the Supply Plan

As stated in Section III.A, above, the Siting Council reviews the adequacy of a gas company's five-year supply plan. In reviewing adequacy, the Siting Council examines whether the

Company's base case resource plan is adequate to meet its projected normal year, design year, design day, and cold-snap firm sendout requirements and, if so, whether the Company's plan is adequate to meet its sendout requirements if certain supplies become unavailable. If the supply plan is not adequate under the base case resource plan or not adequate under the contingency of existing or new supplies becoming unavailable, then the Company must establish that it has an action plan which will ensure that supplies will be obtained to meet its projected firm sendout requirements.

### 1. Normal and Design Year Adequacy

In normal and design year planning, Boston Gas must have adequate supplies to meet several types of requirements. Boston Gas' primary service obligation is to meet the requirements of its firm and quasi-firm customers.[99] In addition, the Company must ensure that its storage facilities have adequate inventory levels prior to the start of the heating season. To the extent possible, Boston Gas also supplies gas to its interruptible customers.

#### a. Base Case Analysis

Boston Gas presented supply plans for meeting its forecasted normal year and design year sendout requirements throughout the forecast period (Exh. BGC-1, Tables G-22N, G-22D). In November, 1991, the Company presented its plans for meeting its revised sendout forecast (id., Tables G-22N, (Revised), G-22D, (Revised)). These plans show that the Company has adequate supplies to meet forecasted sendout requirements under

99/ As noted in Section I.A, above, quasi-firm customers are customers who receive firm service for fewer than 365 days per year. Boston Gas has the same obligation to these customers, during the period in which it serves them, that it does to firm customers.

normal and design conditions throughout the forecast period. The Company's revised design year supply plan is summarized in Tables 2A and 2B, below.

Accordingly, the Siting Council finds that the Company has established that its normal year and design year supply plans are adequate to meet the Company's forecasted sendout requirements and storage refill requirements throughout the forecast period.

b. Contingency Analysis

Boston Gas' supply plan includes (1) the ANE project, which must receive regulatory approval from the Department in DPU 90-156, (2) the Esso project, which requires construction activities outside the Company's control, and (3) the Steuben project, for which the Company, as yet, has no contract. Further, during the course of these proceedings, the Company nominated a conversion of 47,000 MMBtu per day of its firm supply entitlement on the Tennessee pipeline to firm transportation, and the Company is now negotiating contracts to purchase an equivalent volume of gas from five separate suppliers (Exh. BGC-11). The Siting Council, therefore, reviews the adequacy of the Company's supply plan in the event that one of the following contingencies occurs:

(1) a failure to receive regulatory approval of 8.6 MMcf per day of ANE volumes;
(2) a one-year delay in delivery of 35 MMcf per day of Esso volumes;
(3) a failure to execute a contract for 1203 MMcf per year of storage in the Steuben project; and
(4) an interruption in the availability of volumes associated with the largest direct supply contract resulting from the Tennessee conversions (13.2 MMcf per day).

For each individual contingency, Boston Gas provided an analysis, extending to the 1999/2000 split year, showing the year in which the Company would need to acquire additional supplies to meet design year seasonal demand under that contingency (Exhs. HO-FS-13, HO-RR-21, HO-RR-22).[100] These analyses show that, in the event of any of the contingencies, if all other resources remain available to the Company, Boston Gas would not experience a resource deficiency during the forecast period.

Accordingly, the Siting Council finds that Boston Gas has adequate resources to meet forecasted firm and quasi-firm design year sendout requirements in the event of: (1) a failure to receive regulatory approval of 8.6 MMcf per day of ANE volumes; (2) a one-year delay in delivery of 35 MMcf per day of Esso volumes; (3) a failure to execute a contract for 1203 MMcf per year of storage in the Steuben project; or (4) an interruption in the availability of volumes associated with the largest direct supply contract resulting from the Tennessee conversions (13.2 MMcf per day).

### 2. Design Day Adequacy

Boston Gas must have an adequate supply capability to meet its firm customers' design day requirements. While the total supply capability necessary for meeting design year requirements is a function of the aggregate volumes of gas available over some contract period, design day supply capability is determined by the maximum daily deliveries of pipeline gas, the maximum rate at which supplemental fuels can be dispatched, and the quantity of reliable C&LM available on a design day.

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100/ The Company noted that, in its supply planning, it reserves 15 million gallons per year of propane as a contingency against a disruption in LNG deliveries from Distrigas (Tr. 4, p. 85). Thus, each analysis reflected the double contingency of a disruption in LNG deliveries and the stated contingency.

a. Base Case Analysis

Boston Gas presented its design day supply plan to demonstrate that it has adequate resources to meet forecasted firm design day sendout requirements throughout the forecast period (Exh. BGC-1, Table G-23). In November, 1991, the Company presented a plan for meeting its revised design day sendout requirements (id., Table G-23 (Revised)). This plan shows that the Company has adequate resources to meet its forecasted firm design day sendout requirements throughout the forecast period. The Company's revised design day supply plan is summarized in Table 3, below.

Accordingly, the Siting Council finds that the Company has established that its design day supply plan is adequate to meet the Company's sendout requirements for the forecast period.

b. Contingency Analysis

The Siting Council evaluates the Company's design day adequacy under the same four contingencies considered in the normal and design year adequacy analysis (see Section III.C.1.b, above). In the event of either: (1) a failure to receive regulatory approval of 8.6 MMcf per day of ANE volumes; (2) a one-year delay in delivery of 35 MMcf per day of Esso volumes; (3) a failure to execute a contract for 1203 MMcf per year of storage in the Steuben project; or (4) an interruption in the availability of volumes associated with the largest direct supply contract resulting from the Tennessee conversions (13.2 MMcf per day), the Company would not experience a design day resource deficiency throughout the forecast period.

Accordingly, the Siting Council finds that the Company's design day supply plan is adequate to meet forecasted firm design day sendout requirements in the event of: (1) a failure to receive regulatory approval of 8.6 MMcf per day of ANE volumes; (2) a one-year delay in delivery of 35 MMcf per day of Esso volumes; (3) a failure to execute a contract for 1203 MMcf per year of storage in the Steuben project; or (4) an interruption in the availability of volumes associated with the largest direct supply contract resulting from the Tennessee conversions (13.2 MMcf per day).

### 3. Cold-Snap Adequacy and Compliance with Order Seven

In its last decision, the Siting Council ordered Boston Gas to submit an updated cold-snap analysis as part of this filing. 1990 Boston Gas Decision, 19 DOMSC at 429. The Siting Council has defined a cold-snap as a prolonged series of days at or near design conditions. 1991 Colonial Decision, 23 DOMSC at 421; 1990 Boston Gas Decision, 19 DOMSC at 428; 1989 Bay State Decision, 19 DOMSC at 219; 1989 Fitchburg Decision, 19 DOMSC at 120; 1988 ComGas Decision, 17 DOMSC at 137. A gas company must demonstrate that the aggregate resources available to it are adequate to meet this near maximum level of sendout over a sustained period of time, and that it has and can sustain the ability to deliver such resources to its customers. 1991 Colonial Decision, 23 DOMSC at 422; 1990 Boston Gas Decision, 19 DOMSC at 427; 1989 Bay State Decision, 19 DOMSC at 219; 1989 Fitchburg Decision, 19 DOMSC at 120; 1988 ComGas Decision, 17 DOMSC at 137.

As its cold-snap analysis, Boston Gas presented an analysis of its ability in 1992 to meet a 1169 DD February based on weather actually experienced during the month of February, 1979 (Exh. BGC-1, p. 40).[101,102] This month included a ten-day period in which more than 50 DD occurred each day (id., Chart I-B-34). The Company stated that, under these conditions,

101/ The Company stated that in its normal February contains 975 DD, while its design February contains 1079 DD (Exh. BGC-1, p. 40).

102/ In its analysis, the Company assumed that the cold-snap followed normal weather from November, 1991 through January, 1992 (Exh. BGC-1, p. 40).

it would dispatch all contracted pipeline deliveries and supply its remaining requirements with LNG (id.). The Company stated that, at the end of the cold-snap, the Company's LNG inventory would still contain enough liquid for six additional days of production at full vaporization capacity (id., p. 40). The Company also stated that it would not need to dispatch propane at any point during the month (id.).

The Company indicated that it would be able to meet its cold-snap standard during any part of the heating season, due to its design-forward planning standard, under which supplies are dispatched based on the assumption that the rest of the season will consist of design weather (Tr. 4, p. 90).

In the 1990 Boston Gas Decision, the Siting Council found that the Company's choice of a cold-snap standard based on an actual period of extreme weather was appropriate for a company of its size and resources (19 DOMSC at 429). In the instant proceeding, the Company has responded to the Siting Council's order and presented an updated cold-snap analysis which demonstrates that the Company has adequate supplies to meet its firm sendout requirements in the event of a cold-snap during the first year of the forecast period.

Accordingly, the Siting Council finds that the Company has complied with Order Seven of the 1990 Boston Gas Decision. The Siting Council also finds that Boston Gas has established that it has adequate resources to meet its firm and quasi-firm sendout requirements under cold-snap conditions during the first year of the forecast period. In order for the Siting Council to find that the Company's supply plan is adequate in its next forecast, Boston Gas must submit an updated cold-snap analysis.

4. Distribution System Adequacy

a. Compliance with Order Eight

In the 1990 Boston Gas Decision, the Siting Council expressed concern about the discrepancy between the maximum allowable operating pressure ("MAOP") for the Company's Central District[103] system and the Company's internal standard for that system (19 DOMSC at 432-433). The Siting Council noted that unspecified operating constraints led the Company to operate the Central District substantially below MAOP, and that permission from senior management was required to exceed the internal standard. Id. Consequently, in Order Eight, the Siting Council ordered Boston Gas:

> (a) to provide a complete description and analysis demonstrating that under assumed design day conditions the Company can reliably operate its Central District distribution system at pressures above the internal Company standard of 13 to 15 psig up to 22 psig; or (b) to provide a plan to enable the Company to meet its design day requirements without operating above 13 to 15 psig under a reasonable range of supply contingencies which includes an analysis of the limitations that such a plan would place on the Company's ability to use all of its vaporizers simultaneously and at full capacity at its Commercial Point LNG facility. Id. at 435.

In response to this order, Boston Gas clarified the relationship between the MAOP and the Company's internal standard, known as maximum operating pressure ("MOP"), for the Central District. The Company stated that, pursuant to state and federal regulations, the MAOP for the Central District is 22 psig (Exh. BGC-1, p. 102). The Company indicated that its internal standard, currently set at 15 psig, is the actual maximum operating pressure that occurs during normal operations, and that this standard is updated annually (Exh. BGC-12; Tr. 5, p. 9). The Company's witness, Susan Fleck, acknowledged that approval from one of the vice presidents in the operations department was required to exceed the MOP on the Central District system (Tr. 5, p. 31). Ms. Fleck explained that, since the Central District receives supplies from both the Tennessee and Algonquin pipelines, an increase in the operating pressure could change the

103/ The Company's Central District includes Everett, Wellesley, Newton, Milton, and Quincy (Exh. BGC-1, p. 102).

mix of gas taken from Tennessee and Algonquin, which would affect the Company's cost of gas (id., pp. 27-31). Ms. Fleck stated that, since increased pressures could have a direct economic impact on the Company, review by senior management was required (id., p. 27). Ms. Fleck stated that she was familiar with the Central District system, having designed and supervised the construction of district regulator stations for the system, and that there were no engineering or safety reasons why the system should not operate above the internal standard (id., pp. 7, 14-15). The Company also provided a network analysis indicating that the Central District system is capable of meeting anticipated load throughout the forecast period without exceeding MAOP (Exh. BGC-1, Appendix 7).

Boston Gas has offered the testimony of an engineer familiar with the Central District system that the system is capable of operating at its MAOP of 22 psig. While such testimony may not constitute a "complete description and analysis," as required by the Order, the Siting Council recognizes that conducting physical testing to determine the soundness of the distribution system could require system disruption. The Company has also explained that the requirement to consult with senior management before exceeding its internal standard results from the recognition that a change in operating pressure has economic, as well as operational, impacts. Consequently, based on the above and for the purposes of this analysis, the Siting Council finds that the Company has minimally complied with Order Eight.

b. Compliance with Order Nine

In its previous decision, the Siting Council also noted that, despite apparent operational constraints on the Central District system, Boston Gas had not planned or recently installed any reinforcements in the Central District. 1990 Boston Gas

Decision, 19 DOMSC at 435. Consequently, in Order Nine, the Siting Council ordered the Company to:

> (a) provide a complete description and analysis of the reason or reasons for not planning reinforcements for the Central District in light of operating constraints in this part of its distribution system; and (b) if reinforcements are planned, to provide an itemized list of such reinforcements and an explanation of their expected impact on such operating constraints. Id. at 435.

In response to this Order, the Company presented a series of network analyses for the Central District system for the first and last years of the forecast period (Exh. BGC-1, Appendix 7). Ms. Fleck explained that these studies determined the pressure at all points in the system, given the pressure at the take stations feeding the system and the expected load at all points in the system (Tr. 5, p. 17). Ms. Fleck stated that, for each analysis, pressures at the take stations were adjusted until all end points had adequate minimum pressures (id., p. 18). The Company indicated that its most extreme case, the peak hour of a 75 DD in 1995-96, required pressures of 20 psig at the Wellesley, Commercial Point and Everett stations, and 18.5 psig at Chelsea Run (Exh. BGC-1, p. 104). Ms. Fleck testified that the Central District system is capable of operating at these pressures (Tr. 5, pp. 20-21). The Company stated that, since the Central District System is capable of meeting anticipated load during the forecast period without systematic upgrade or reinforcement, no reinforcement is planned for the system beyond routine maintenance (Exh. BGC-12, p. 6).

Boston Gas has indicated that it does not plan Central District reinforcements during the forecast period because the system is capable of meeting anticipated load throughout the forecast period without reinforcements. In support of its contention, the Company has presented testimony that the Central District System is capable of operating at its MAOP of 22 psig, and a study indicating that design load for the Central District system can be met throughout the forecast period with pressures no higher than 20 psig. Consequently, the Siting Council finds that the Company has complied with Order Nine.

### 5. Conclusions on the Adequacy of the Supply Plan

The Siting Council has found that (1) the Company has established that its normal year and design year supply plans are adequate to meet the Company's forecasted sendout requirements and storage refill requirements throughout the forecast period, and (2) that Boston Gas has adequate resources to meet forecasted firm and quasi-firm design year sendout requirements in the event of: (1) a failure to receive regulatory approval of 8.6 MMcf per day of ANE volumes; (2) a one-year delay in delivery of 35 MMcf per day of Esso volumes; (3) a failure to execute a contract for 1203 MMcf per year of storage in the Steuben project; or (4) an interruption in the availability of volumes associated with the largest direct supply contract resulting from the Tennessee conversions (13.2 MMcf per day).

The Siting Council also has found that (1) the Company has established that its design day supply plan is adequate, and (2) the Company's design day supply plan is adequate to meet forecasted firm design day sendout requirements in the event of: (1) a failure to receive regulatory approval of 8.6 MMcf per day of ANE volumes; (2) a one-year delay in delivery of 35 MMcf per day of Esso volumes; (3) a failure to execute a contract for 1203 MMcf per year of storage in the Steuben project; or (4) an interruption in the availability of volumes associated with the largest direct supply contract resulting from the Tennessee conversions (13.2 MMcf per day).

Further, the Siting Council has found that the Company has complied with Order Seven of the <u>1990 Boston Gas Decision</u>, and that the Company has established that it has adequate resources to meet its firm and quasi-firm sendout requirements under cold-snap conditions during the first year of the forecast period. Finally, the Siting Council has found that the Company has minimally complied with Order Eight and complied with Order Nine regarding the adequacy of the Central District distribution system.

Accordingly, the Siting Council finds that Boston Gas has established that it has adequate resources to meet its firm and quasi-firm sendout requirements throughout the forecast period.

D. Supply Planning Process

1. Standard of Review

The Siting Council has determined that a supply planning process is critical in enabling a utility company to formulate a resource plan that achieves an adequate, least-cost and low environmental impact supply for its customers. 1991 Colonial Gas Decision, 23 DOMSC at 391; 1990 Boston Gas Decision, 19 DOMSC at 388; 1990 Berkshire Decision (Phase 1), 19 DOMSC at 283; 1989 Bay State Decision, 19 DOMSC at 182; 1989 Fitchburg Decision, 19 DOMSC at 126-127; Boston Edison Company, 18 DOMSC at 201, 224-226, 250-281 (1989); Eastern Edison Company, 18 DOMSC 73, 100-103, 111-131 (1988); 1987 Boston Gas Decision, 16 DOMSC at 247-248. The Siting Council has noted that an appropriate supply planning process provides a gas company with an organized method of analyzing options, making decisions, and reevaluating decisions in light of changed circumstances. 1991 Colonial Gas Decision, 23 DOMSC at 392; 1990 Berkshire Decision, 19 DOMSC at 284; 1990 Boston Gas Decision, 19 DOMSC at 388; 1989 Bay State Decision, 19 DOMSC at 182. For the Siting Council to determine that a gas company's supply planning process is appropriate, the process must be fully documented. 1991 Colonial Gas Decision, 23 DOMSC at 392; 1990 Boston Gas Decision, 19 DOMSC at 388; 1989 Bay State Decision, 19 DOMSC at 38; 1987 Boston Gas Decision, 16 DOMSC at 247, 249; 1987 Berkshire Gas Decision, 16 DOMSC at 84.

The Siting Council's review of a gas company's supply planning process has focussed primarily on whether (1) the process allows companies to adequately consider C&LM options, and (2) the process treats all resource options -- including C&LM options -- on an equal footing. 1991 Colonial Gas Decision, 23 DOMSC at 392; 1990 Boston Gas Decision, 19 DOMSC at 389; 1990 Berkshire Decision (Phase 1), 19 DOMSC at 283; 1989 Bay State Decision, 19 DOMSC at 179; 1989 Fitchburg Decision, 19 DOMSC at 123-124; 1988 ComGas Decision, 17 DOMSC at 138-139; 1987 Bay State Decision, 16 DOMSC at 323; 1987 Boston Gas Decision, 16 DOMSC at 252; 1987 Berkshire Decision, 16 DOMSC at 85; 1986 Fall River Decision, 15 DOMSC at 115.

The Siting Council review of a gas company's process for identifying and evaluating resources focusses on whether the company (1) has a process for compiling a comprehensive array of resource options -- including pipeline supplies, supplemental supplies, C&LM, and other resources; (2) has established appropriate criteria for screening and comparing resources within a particular supply category; (3) has a mechanism in place for comparing all resources, including C&LM, on an equal footing, i.e., across resource categories, and (4) the process as a whole enables the company to achieve an adequate, least-cost, and low environmental impact supply plan. 1991 Colonial Gas Decision, 23 DOMSC at 393; 1990 Boston Gas Decision, 19 DOMSC at 389; 1989 Fitchburg Decision, 19 DOMSC at 54-55; 1989 Bay State Gas Decision, 19 DOMSC at 39.

### 2. Identification and Evaluation of Resource Options

#### a. Overview

Boston Gas stated that its planning process is intended to develop a least-cost supply plan, which the Company defined as a mix of resources which minimizes the average cost of gas over time (Exh. BGC-3, p. 16). The Company indicated that its process is designed to allow resources "to be evaluated on a consistent basis with appropriate documentation and analysis" (Tr. 4, p. 13).

Boston Gas stated that it has created an interdepartmental task force to refine the Company's planning processes and make resource decision recommendations (Exh. BGC-2, pp. 3-4). In the fall of 1990, this Integrated Resource Management ("IRM") Task Force produced a "Report on Integrated Resource Management," which laid out a seven-step supply planning process including: (1) demand forecasting, (2) determination of resource characteristic requirements, (3) identification and ranking of supply-side alternatives, (4) identification and ranking of demand-side alternatives, (5) initial selection of supply-side resources, (6) calculation of avoided costs, and (7) integrated selection of demand and supply-side resources (Exh. BGC-1, Appendix 4, pp. 6-8).

Boston Gas stated that, under its IRM process, it determines the size, nature (baseload, seasonal or peak), and timing of its resource need by modelling sendout based on demand forecasts developed by the business forecasting department (Tr. 4, p. 17). The Company recognized that its demand forecasts include avoidable demand, but did not discuss how this fact influences the planning process (id., p. 21).[104]

Boston Gas also presented a June, 1991 study undertaken by Decision Focus Incorporated ("DFI"), which reviewed the Company's planning tools and processes (Exh. BGC-1, p. 83, Appendix 4, Appendix 5). DFI reported that Boston Gas has appropriate analytical tools for all of the components of its IRM process

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104/ The Company noted that, although it has historically foregone growth which does not provide economic benefits to existing ratepayers, it now believes that there may be situations in which such growth should be pursued (Exh. BGC-2, p. 6). For further discussion of this issue, see Section III.E.3, below.

except the valuing of certain non-price factors;[105] however, DFI noted that these tools are time-consuming to use, which limits the Company's ability to do detailed sensitivity analysis (id., Appendix 5, p. iii). Boston Gas indicated that it intends to acquire a modelling tool ("the contract mix model") from DFI which will simplify sensitivity analysis (Tr. 4, pp. 14-15).

In its description of its IRM process, the Company indicated that it has parallel processes for identifying and evaluating supply-side and demand-side resource options. The Company also described a separate process for acquiring spot supplies. The Siting Council therefore reviews the Company's identification and evaluation processes for the following three groups: (1) supply-side resources, i.e. pipeline and supplemental supplies and capacity, including firm gas contracts, pipeline capacity, storage capacity, LNG and propane; (2) C&LM resources; and (3) spot gas.

b. Supply-Side Resources

i. Description of Supply Planning Process

As noted in Section III.B, above, Boston Gas' supply-side portfolio includes firm pipeline supplies, firm and interruptible transportation, third party gas contracts, storage services, LNG and propane.

Boston Gas indicated that the supply planning department is responsible for the identification of potential supply-side resources (Tr. 4, p. 24). Mr. Gulick stated that the Company identifies pipeline options primarily through day-to-day contacts with producers, pipelines and marketers, as well as through the trade press and trade groups (id., p. 110). He noted that the Company is in contact with developers of storage fields about

105/ DFI recommended that the Company adopt a "probabilistic planning approach" to evaluating non-price factors. This recommendation is discussed in Section III.F.1, below.

current storage offerings (id., p. 112). He also stated that LNG can be purchased from Distrigas or from other LDCs, and that propane can be purchased from numerous suppliers on the open market (Tr. 5, p. 131).

Boston Gas indicated that supply decisions involving the addition of major new supply increments are evaluated by the IRM Task Force (Exh. BGC-1, pp. 82-83). The Company indicated that, in its IRM process, it evaluates supply-side resources relative to each other based on load fit,[106] price,[107] and non-price criteria (Tr. 4, p. 25). The Company stated that flexibility and diversity[108] of the resource portfolio are its primary non-price considerations, but that it also takes into account attributes such as operational benefits, regulatory uncertainty, and political implications insofar as they affect a particular resource decision (id., pp. 25-26; Exh. HO-PL-14).

The Company indicated that certain decisions, such as the decisions to retire the Everett SNG production plant and the Dorchester LNG storage tank, were made primarily by the gas supply planning department based on cost analyses and the availability of alternative resources (Exh. BGC-3, p. 9; Tr. 5, pp. 120-121, 125).

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106/ The Company indicated that "load fit" describes the extent to which the seasonality and magnitude of a resource option match the seasonality and magnitude of the perceived need (Tr. 4, p. 27).

107/ The Company stated that it includes monetized environmental externalities in the cost of potential resources, but noted that environmental externality costs do not differ among supply-side resources (Exh. PL-14). The Company indicated that it derived its own externality values in evaluating its residential DSM programs, but adopted the DPU values once they became available (see DPU 90-55, at 132; DPU 90-320 at 27).

108/ The Company indicated that flexibility includes flexibility of on-line date and take, while diversity includes diversity of supply type and resource provider, an appropriate mix of firm and interruptible supplies, and diversity in contract length, renewability, and expiration date (Exh. HO-PL-14).

ii. Analysis

Boston Gas has demonstrated that it has in place processes which allow it to identify a variety of pipeline and supplemental supply and capacity options. The Company has also identified a reasonable set of price and non-price criteria which allow it to determine which options to pursue.[109]

The Company's discussion of its supply planning process has focussed on its IRM process and the IRM Task Force, through which decisions regarding new supply acquisitions are made. However, the Company has also made a series of supply decisions which do not involve the acquisition of new supplies; these have been made primarily by the gas supply planning department, without formal IRM Task Force involvement. The Siting Council accepts that it may be appropriate for simple, relatively minor supply decisions to be made in a less formal manner, so long as consistent price and non-price criteria are considered, and the decisions are integrated with those from the IRM process.

Accordingly, the Siting Council finds that the Company's process for identifying and evaluating supply-side resources is an appropriate means for deciding among such supply options.

In its previous decision, the Siting Council directed Boston Gas to include an adequate consideration of the environmental impacts of resource options in its supply planning process, pursuant to the Council's enabling statute. 1990 Boston Gas Decision, 19 DOMSC at 404-405. In this filing, the Company included monetized environmental externalities in its evaluation of conservation options, and asserted that the environmental impacts of supply-side options are identical. In the future, the Company should either justify this assertion in some detail, or discuss more explicitly the role which consideration of environmental impacts plays in the Company's planning process.

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109/ The Siting Council discusses the Company's use of non-price criteria for both supply-side and demand-side resources in Section III.F.1, below.

c. Conservation and Load Management

i. Description of Planning Process

Boston Gas stated that, to identify C&LM[110] resource options, it contracted with an engineering firm, Energy Investment, Inc. ("EII"), to conduct a technical potential[111] study of the energy-savings opportunities within the Company's service territory (Tr. 5, p. 153; Exh. DSM-1). The EII study was based on energy audit field data,[112] market research information from the Company's 1986 Residential Appliance Saturation Survey, and annual sales data from the demand forecasting model (Exhs. HO-DSM-1, HO-DSM-2; Tr. 5, p. 153). Boston Gas used the results of this study to evaluate conservation resources (Exh. HO-DSM-1).

Boston Gas indicated that it asked EII to (1) assess the nature and size of DSM technical potential in its service territory, (2) identify a full range of conservation technologies and determine their cost-effectiveness based on the Company's avoided cost, and (3) prepare estimates of implementation costs and gas savings (Exh. HO-DSM-2). The EII study identified 22 residential conservation measures and 45 commercial and light industrial measures based on the audit data (Exh. DSM-1, Attachment 1). Because the audit data represented primarily residential and commercial customers, EII provided supplemental

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110/ For the purposes of this decision, the Siting Council uses the terms "C&LM", "DSM", and "demand-side resources" interchangeably.

111/ The Company defines "technical potential" as the savings potential from the installation of C&LM technologies that are cost-effective when looked at individually, assuming 100 percent penetration of the remaining market (Exh. DSM-1, DPU 90-55, at 87, n. 5).

112/ The customer-specific energy audit field data and energy savings estimates utilized in the study were obtained from actual field data collected by the Company's Energy Conservation Service program vendor, MassSave, Incorporated ("MassSave") (Exh. DSM-2).

data on a range of process-related measures for industrial customers (id.). The Company's witness, Beth S. Greenblatt, also indicated that the Company considered some C&LM measures, such as heating system replacement options, that were "not completely developed" as part of the technical potential study (Tr. 5, p. 154).

Consistent with DPU practice, Boston Gas selected C&LM resources using a societal cost test comparing the cost of the C&LM measures to the Company's avoided costs, plus monetized externalities (Exh. BGC-1, p. 69).[113] The Company looked at the maximum savings potential of all possible conservation measures and those measures that were cost-effective on a stand-alone basis (Tr. 5, p. 161). Once Boston Gas determined which measures were cost-effective, the Company compared the value of the gas savings against the avoided cost plus monetized externality values (id., p. 167). The Company then determined which bundle of measures would produce the greatest net benefits to society (id., pp. 161-162).

Ms. Greenblatt indicated that, in evaluating conservation resources, Boston Gas applies non-price factors similar to those applied to the supply-side resources (id., p.155). Ms. Greenblatt cited flexibility, diversity, and reliability as the primary non-price criteria that should be considered in the evaluation of demand-side resources (id., pp. 155-157). Ms. Greenblatt noted that C&LM resources are flexible in size and

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113/ The DPU's test for determining the cost-effectiveness of a particular measure is the so-called "net social benefits" test (Exh. HO-DSM-1, DPU 90-55, at 113). This standard takes into account all costs and benefits of a C&LM program, "whether befalling the utility, program participant, or society" (id.). The DPU has specified that program costs include: (1) the full incremental cost of the measures, regardless of who pays; (2) all installation costs; (3) all administrative costs; and (4) all evaluation and monitoring costs. Program benefits under the DPU test include: (1) the avoided cost savings; (2) environmental externalities; and (3) any quantifiable end-user benefits. DPU 90-320 at 23-24.

timing of implementation, and diverse in load profile (id., pp. 156-157). Ms. Greenblatt stated that, while non-price criteria were "considered" when the Company developed its existing C&LM programs, they would play a more integral role in the C&LM planning process as the IRM process progressed (id., p. 157).

Boston Gas indicated that it is sponsoring the New England States Gas Evaluation and Monitoring Study ("GEMS"), a three-year study which will measure the savings from conservation measures by end-use metering of the gas consumption of space heating systems and water heaters (Exh. BGC-1, pp. 74, 76, Appendix 2, p. 2-4, Appendix 3, p. E-1). The Company indicated that metering activities for each customer sector will be supplemented with customer research, including focus groups (id., pp. 77-78). The Company stated that the research and metering activities are designed to: (1) measure the magnitude and timing of energy savings; (2) determine program participation factors; (3) track program costs; and (4) verify the remaining market (id., p. 78). The Company stated that the results of the study will be used to evaluate future C&LM resource options (Exh. BGC-1, pp. 78-79).

ii. Analysis

In a previous decision, the Siting Council has stated that territory-specific energy audit field data "can be an appropriate starting point for the identification of potential conservation resources." 1991 Colonial Gas Decision, 23 DOMSC at 406. The Siting Council noted, however, that utilities should not rely exclusively upon such audit data, since "cost-effective conservation resources not included in earlier audits will be overlooked" Id.

Here, the EII study relied upon by Boston Gas to identify and evaluate C&LM resource options was based not only on energy audit field data, but also on market research information and supplemental data from EII and other sources. As a result, the

Company identified and evaluated a range of conservation measures beyond those included in the audit data. In addition, the Company considered heating replacement options, which were not fully developed in the audit data, and has proposed a heating replacement program based on this additional information. The Siting Council encourages the Company to continue to pursue the identification of new C&LM measures. In particular, the Siting Council joins the Department in encouraging the Company to analyze ways to capture C&LM savings at the time of new construction, renovations, remodeling, and facility expansion. See DPU 90-320 at 18.

The Siting Council notes that Boston Gas has developed a detailed and comprehensive process for evaluating conservation resources. The Company has presented cost/benefit studies based on its avoided costs and on territory-specific audit and survey data. Boston Gas also has indicated its intention to evaluate conservation measures based on a variety of non-price criteria. The Siting Council has repeatedly emphasized the need to incorporate the consideration of non-price criteria into a gas company's decision to acquire conservation resources. 1991 Colonial Gas Decision, 23 DOMSC at 407; 1990 Boston Gas Decision, 19 DOMSC at 401-402; 1990 Berkshire Decision (Phase I), 19 DOMSC at 295-296; 1989 Bay State Decision, 19 DOMSC at 190-191. Based on the above, the Siting Council finds that the Company's process for identifying and evaluating C&LM resources is an appropriate means for deciding among such C&LM options.

In making this finding, however, the Siting Council notes that the IRM process evaluates DSM options after supply-side options have been selected. For a further discussion of this issue, see Section III.D.3, below.

d. Spot Gas Supplies

Boston Gas stated that it purchases spot gas to substitute for more expensive gas supplies whenever possible (Exh. BGC-1,

p. 40). Mr. Gulick indicated that the Company receives bids from suppliers approximately five days before the end of each month, and negotiates purchases and transportation based on those bids (Tr. 5, p. 128). Mr. Gulick stated that the Company generally selects suppliers offering spot gas at the lowest cost, although it also considers the reliability of the supplier (id.).

The Company indicated that its spot gas purchases resulted in savings of $38 million in 1989, $75 million in 1990, and $28 million in the first five months of 1991 (Exh. BGC-1, Chart I-B-35).[114]

In the 1990 Boston Gas Decision, the Siting Council found that it was appropriate for Boston Gas to have a separate process for identifying and evaluating spot gas, and that the Company's formal bidding process was an appropriate means of identifying least-cost spot gas supplies (19 DOMSC at 395). Here, the Company has demonstrated the benefits of this process through the considerable cost savings that it has achieved for its ratepayers.

Accordingly, the Siting Council finds that the Company's process for identifying and evaluating spot gas supplies is an appropriate means of deciding among spot options.

### 3. Consideration of All Resources on an Equal Footing

The Siting Council has consistently held that, in order for a gas company's planning process to minimize cost, that process must adequately consider alternative resource additions, including C&LM options, on an equal basis. 1991 Colonial Decision, 23 DOMSC at 409; 1990 Boston Gas Decision, 19 DOMSC at 402; 1990 Berkshire Decision (Phase 1), 19 DOMSC at 296; 1989 Bay

114/ In 1989, this represented savings of 27 percent over the equivalent cost of pipeline gas during the months in which spot gas was available; the savings were 43 percent and 46 percent in 1990 and 1991, respectively (Exh. BGC-1, Chart I-B-35).

State Decision, 19 DOMSC at 195; 1989 Fitchburg Decision, 19 DOMSC at 123; 1988 ComGas Decision, 17 DOMSC at 138-139; 1987 Bay State Decision, 16 DOMSC at 85; 1987 Boston Gas Decision, 16 DOMSC at 252; 1986 Fall River Decision, 15 DOMSC at 115.

In the 1990 Boston Gas Decision, the Siting Council noted that, while Boston Gas had established a process which allowed it to evaluate the costs of supply-side and C&LM resources on an equal footing, the Company did not evaluate the non-price characteristics of supply and C&LM resources on an equivalent basis (19 DOMSC at 403). The Siting Council also noted that the Company's planning process did not ensure that a reasonable range of options were evaluated at times when resource decisions were being made. Id.

In this proceeding, Boston Gas has demonstrated considerable progress in developing a set of non-price criteria which can be used to evaluate both supply-side and demand-side resources. The Company has provided an example of the use of these criteria in the evaluation of supply-side resources. However, the Company has provided comparatively little information on the use of these criteria to evaluate C&LM resources.

Further, the Company has explicitly stated that it will not, at this time, consider backing off supply-side acquisitions in favor of conservation resources, despite the fact that the Department has approved conservation programs whose estimated savings considerably exceed the size of the Company's ANE contract (see Exh. DPU-4). The Company argues that it does not have sufficient information on the magnitude and reliability of conservation savings to treat them as part of its firm portfolio, and states that it intends to await the results of its GEMS monitoring program before incorporating C&LM into its base case supply plan (Exh. BGC-1, p. 95; Tr 5, pp. 53-54).

The Siting Council has specifically rejected this "wait and see" approach to conservation, noting that, while a company "waits" for conservation programs to prove themselves, it runs the risk of obtaining unnecessary supply resources and subjecting its ratepayers to higher costs. 1989 Bay State Decision, 19 DOMSC at 233. When a company undertakes large-scale conservation programs, as Boston Gas has done, it cannot ignore the resources which these programs provide. Rather, at a minimum, the Company should treat conservation as a potential supply resource to which attrition will apply, and evaluate its contribution to the Company's supply portfolio under several scenarios. The Siting Council recognizes that Boston Gas is leading a state-wide effort by gas companies to develop verified conservation savings data. However, this does not excuse the Company's current assumption that its conservation programs will provide no reliable resources whatsoever.

Consequently, based on the Company's statements that it has chosen in this filing not to treat conservation resources as a legitimate supply option, and evidence which indicates that conservation has not been so considered, the Siting Council finds that the Company's supply planning process does not treat all supply options on an equal footing. In order for the Siting Council to approve the Company's supply planning process in its next filing, the Company must develop and implement some methodology for recognizing and accounting for the resources provided by existing and planned conservation programs in both its base case supply plan and its supply planning process.

### 4. Conclusions on the Supply Planning Process

The Siting Council has found that (1) Boston Gas' process for identifying and evaluating supply-side resources is an appropriate means for deciding among such supply options, (2) the Company's process for identifying and evaluating C&LM resources is an appropriate means for deciding among such C&LM options, and (3) the Company's process for identifying and evaluating spot gas supplies is an appropriate means of deciding among spot options.

The Siting Council has also found that the Company's supply planning process does not treat all supply options on an equal footing. This finding raises questions regarding the Company's ability to select a least cost portfolio of supply-side and demand-side resources.

On balance, therefore, the Siting Council finds that the Company's supply planning process enables it to identify a reasonable range of resource options and to perform a minimally adequate evaluation of such options. Accordingly, the Siting Council finds that the Company has established that its supply planning process, properly applied, is minimally sufficient to enable it to make least-cost supply decisions.

E. Least Cost Supply

1. Standard of Review

As set forth in Section III.A, above, the Siting Council reviews a gas company's five-year supply plan to determine whether it minimizes cost, subject to trade-offs with adequacy and environmental impact. 1991 Colonial Decision, 23 DOMSC at 425; 1990 Boston Gas Decision, 19 DOMSC at 438; 1989 Bay State Decision, 19 DOMSC at 224; 1989 Fitchburg Decision, 19 DOMSC at 124, 127; 1988 ComGas Decision, 17 DOMSC at 109; 1987 Bay State Decision, 16 DOMSC at 309; 1987 Berkshire Decision, 16 DOMSC at 72; 1987 Boston Gas Decision, 16 DOMSC at 214. A gas company must establish that the application of its supply planning process -- including adequate consideration of C&LM and consideration of all options on an equal footing -- has resulted in the addition of resource options that contribute to a least cost supply plan. As part of this review, the Siting Council continues to require gas companies to show, at a minimum, that they have completed comprehensive cost studies comparing the costs of a reasonable range of practical supply alternatives prior to selection of major new resources for their supply plans. 1991 Colonial Gas Decision, 23 DOMSC at 425; 1990 Boston Gas

Decision, 19 DOMSC at 438; 1989 Bay State Decision, 19 DOMSC at 224; 1989 Fitchburg Decision, 19 DOMSC at 124; 1987 Bay State Decision, 16 DOMSC at 319; 1986 Gas Generic Order, 14 DOMSC at 100-102.

2. Least Cost Analysis

Boston Gas has included three new long-term pipeline supply projects in its base case supply plan: ANE, Esso, and an additional increment of the PennEast CDS project (see Section III.B.1, above). In addition, the Company has indicated its intention to convert a portion of its Tennessee CD-6 sales contract to firm transportation and to purchase replacement volumes directly from gas producers. Finally, the Company has made several decisions relating to supplemental storage and capacity and to the implementation of C&LM programs in the forecast period.[115]

The Siting Council reviewed Boston Gas' plans to obtain pipeline supplies from the Esso and ANE projects in its previous decision. 1990 Boston Gas Decision, 19 DOMSC at 446-453. In that decision, the Siting Council criticized the Company for inconsistencies in its cost analysis, use of an inappropriate time frame for analysis, failure to compare the volumes with a reasonable range of supply alternatives, failure to present evidence regarding its choice of MDQ, and failure to conduct appropriate sensitivity analyses. Id. at 450-451. The Siting Council also ordered the Company to provide additional studies of the ANE and Esso volumes in this filing. Id. at 453. The Siting

115/ Although the Company included the proposed Steuben storage volumes in its base case supply plan beginning in 1993 as required by Order A, the Company is still in the early stages of negotiations with the Steuben developers, and has not yet undertaken a detailed evaluation of the resource. Consequently, the Siting Council is unable to evaluate the Company's application of its supply planning process to decisions regarding the proposed project.

increment, the ANE volumes at zero, seven, and 17 BBtu/day, firm and interruptible transportation on Algonquin for the PennEast increment, and the purchase of seven BBtu/day of an unspecified supply beginning in 1996/97 (Exh. BGC-1, Chart I-D-1).[116] The Company indicated that it performed a cost study comparing the supply scenarios and considered the non-price implications of each alternative (id., pp. 90-91).

Boston Gas presented the results of its 1990 cost study, which evaluated the net benefits to ratepayers of each scenario under base and high demand forecasts,[117] and base and high interruptible margins (id., Chart I-D-2).[118] The Company indicated that the impact on ratepayers of each scenario included: (1) changes in the cost of gas, (2) changes in revenues from new firm loads, and (3) changes in revenues from sales to interruptible customers (Tr. 6, pp. 31, 45, 76).[119]

The Company indicated that its cost study assumed that, until its portfolio sold out in firm markets, all incremental gas would be sold into the interruptible market 365 days a year (Tr. 6, p. 46). The Company stated that it used a 29-year time frame

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116/ A listing of these scenarios appears in Table 4.

117/ The Company stated that its base case demand forecast was prepared in the summer of 1990 using the methodologies described in Section II, above, while the high case demand forecast was identical to the base case except that it assumed higher growth rates throughout 1991 due to the effects of the Persian Gulf crisis (Tr. 6, p. 28).

118/ The interruptible margin is the Company's average profit margin on sales to interruptible customers. The Company used a base interruptible margin of $0.15 and a high margin of $0.40 (Exh. BGC-1, Chart I-D-2). Ms. Fenton noted that the Company's average margin in 1990 was $0.19, while the average margin in 1991 was $0.24 (Tr. 7, p. 12).

119/ The addition of new firm customers can lower rates by spreading the Company's fixed costs over a greater number of customers. The Company's profit on sales to interruptible customers is credited directly to firm customers.

Council reviews the Company's response to this order in Section III.F.2, below.

Boston Gas' overall supply planning process, and the impact of its supply decisions on the adequacy of the Company's supply plan, have been reviewed in Sections III.D and III.C, above. Here, the Siting Council reviews the Company's actual application of its supply planning process in making decisions regarding the ANE project, the PennEast CDS increment, the Tennessee conversions, supplemental supply decisions, and C&LM programs, in order to determine whether each of these supply decisions contributes to a least-cost supply plan.

a. ANE and PennEast Volumes

i. Overview

Ms. Miller indicated that, in the fall of 1990, the Company had an opportunity to withdraw completely from the ANE project, as ANE had failed to meet a project milestone (Tr. 7, p. 47). At the same time, Boston Gas was offered the opportunity to increase its take of the PennEast CDS project by 10 MMcf/day (id., p. 48). The Company therefore evaluated these two supply resources simultaneously, and determined to take the additional PennEast increment, while reducing its ANE takes by approximately 10 MMcf/day through sales to other companies (Exh. BGC-1, p. 91). The Siting Council reviews the planning process which resulted in this decision, and determines whether the PennEast CDS increment and the remaining ANE volumes contribute to a least cost supply plan.

ii. Application of the Supply Planning Process

Boston Gas indicated that, in the fall of 1990, it compared its base case supply scenario of 17 BBtu/day of ANE and no additional PennEast increment with eight alternative supply scenarios, which included various combinations of the PennEast for its analysis, based on the year in which the portfolio sells out in firm markets, plus the average life of customer equipment, which it estimated at 20 years (Exh. HO-PL-6). The Company argued that the impacts of a supply addition accrue over the life of the load added using that supply, rather than the life of the contract (id.).

The Company's 1990 cost study indicated that, in the base demand/base interruptible margin case, ratepayers received the most benefits from the scenario, designated Scenario 6, in which the Company took the additional PennEast increment, reduced its ANE take to 7 BBtu/day, and used interruptible transportation (Exh. BGC-1, Chart I-D-2). The second best scenario, Scenario 2, was one in which the Company took the additional PennEast increment, eliminated ANE, and used interruptible transportation (id.).[120] Scenario 2 provided the greatest reductions in the cost of gas; however, Scenario 6 provided firm and interruptible sales revenues to offset its higher gas costs (id.) The ranking of the scenarios was sensitive to both the demand forecast and the interruptible margin (id.).

The Company indicated that the non-price considerations which supported its decision to switch some volumes from the ANE project to the PennEast project included flexibility, rate design uncertainty, and abandonment rights (Exh. BGC-1, pp. 91-93).[121]

120/ Two other scenarios, 7 and 8, actually outperformed Scenarios 6 and 2; however, these made the assumption that the Company would be able to purchase an additional 7 BBtu/day from some unspecified source at a similar price in 1996-97 (Exh. BGC-1, Charts I-D-1 and I-D-2). The Company argued that it had no reasonable basis to assume such volumes would be available at that time, and that Scenarios 7 and 8 were therefore useful benchmarks, rather than practical supply options (Exh. BGC-1, p. 94).

121/ Boston Gas stated that it also considered whether the reliability benefits of firm service on Algonquin for the PennEast volumes outweighed the price benefits of interruptible service, and determined that they did not because (1) the Company did not need these volumes on peak day, (2) interruptible

The Company stated that the PennEast volumes provided additional flexibility to the Company's supply portfolio, in that they could be converted to pipeline transportation, and the excess capacity could be brokered (id., pp. 102-103). The Company also indicated that, at the time of its decision, the rate structure for Canadian exports had not been settled (Tr. 7, p. 54). The Company stated that an adverse decision on rate structure by Canadian authorities might have resulted in higher ANE prices and perhaps in the cancellation of the project (id.). Finally, the Company noted that the pipeline could not abandon the PennEast service without a hearing at FERC, while the ANE service had no such regulatory protection (Exh. BGC-1, p. 93).

Boston Gas stated that the non-price considerations which supported the retention of some ANE volumes included flexibility, diversity, operational benefits, and political implications (Exh. BGC-1, pp. 92-94; Tr. 7, p. 59). The Company indicated that ANE's seasonal pricing, and the ability to reduce takes to 60 percent of the contracted volumes without incurring a penalty, contributed to the flexibility of the supply portfolio (Exhs. HO-RR-31, BGC-1, p. 93). The Company stated that the criterion of diversity of suppliers argued for retaining some ANE volumes (Exh. BGC-2, p. 9). The Company noted that, with ANE, it acquired an additional take station and more capacity on the Tennessee pipeline, which would allow the Company to make more effective use of its distribution system and to take more advantage of differences in gas costs between the Tennessee and Algonquin pipeline systems (Tr. 7, pp. 107-108).

Finally, Boston Gas stated that it was concerned that its complete withdrawal from the ANE project might jeopardize both

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transportation on Algonquin is readily available for much of the year, (3) Boston Gas has a relatively high place in Algonquin's interruptible queue, and (4) the Company could convert to firm transportation at any time with 18 months notice (Exh. BGC-1, pp. 94-95).

the ANE project and the Iroquois pipeline (Exh. BGC-1, p. 92). The Company stated that the ANE project developers had indicated that project financing might be threatened by the withdrawal of Boston Gas, which is the largest local distribution company ("LDC") in New England, and that the collapse of the project might jeopardize the Iroquois pipeline project (Tr. 7, pp. 57-58, 64-65). Boston Gas further stated that, at the time, both financial institutions and Canadian producers were questioning whether there was sufficient market demand in the Northeast to support sizable exports (Exh. BGC-1, p. 92; Tr. 7, p. 57). The Company noted that the loss of the ANE project would have serious implications for other Massachusetts LDCs, while the collapse of the Iroquois pipeline project would threaten its own Esso volumes (Exh. BGC-1, pp. 92-93). The Company also noted that an independent source of supply, such as the Iroquois pipeline, would encourage more competitive pricing by domestic producers, thereby providing further benefits to Boston Gas and to other LDCs (Tr. 7, p. 56).

Boston Gas stated that it did not consider conservation as an alternative supply resource in its analysis, due to "the limited information available on the magnitude and timing of DSM savings" (Exh. BGC-2, pp. 9-10). Further, while the Company provided the Siting Council with information indicating that, between January, 1990 and September, 1991, city gate prices for DOMAC LNG were generally lower than city gate prices for ANE, the Company stated that it did not consider DOMAC LNG as a possible supply alternative for reasons of reliability and diversity (Exh. HO-PL-25; Tr. 7, pp. 100-102). Mr. Gulick noted that DOMAC LNG already comprises a large portion of the Company's peak day supply portfolio, and stated that he believed that the logistics of LNG delivery from Algeria made LNG a less reliable resource than pipeline gas (Tr. 7, pp. 100-102).

Boston Gas stated that it developed contingency plans for the event that its markets do not develop as forecast

(Exh. BGC-1, p. 96). The Company stated that, in this event, it could assign supply temporarily to a third party, revise its supply portfolio to reduce its fixed costs and commodity costs, or develop other markets for the gas (id., p. 97). The Company stated that it could assign supplies to a third party either through the gas supply assignment provisions in its ANE contract or by brokering its capacity (id., p. 96; Tr. 6, pp. 127-128). The Company indicated that it could sell additional supplies to large end-use markets, obtain a blanket certificate for interstate sales from FERC, attract new customers by adjusting customer contributions and incentives for new hook-ups, and offering volume breaks in its commercial/industrial rate structure (id.).[122]

At the Siting Council's request, the Company provided an additional cost analysis which compared the base case supply plan to six alternative scenarios, including one which included neither the ANE volumes nor the PennEast increment (Exh. HO-PL-22).[123,124,125] The Company evaluated these scenarios

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122/ The Company stated that it was already selling into large end-user markets, that it had applied for a blanket certificate, and that it was currently offering some commercial/industrial price breaks (Tr. 6, pp. 129-131). The Company indicated that it was considering stimulating sales by adjusting customer contributions and hook-up incentives, but had not yet decided to do so (id., pp. 130-131).

123/ A listing of these scenarios, and the demand/interruptible margin cases over which they were evaluated, appears in Table 5.

124/ The Company revised this analysis twice, once to correct its low demand forecast, and once to eliminate double-counting of firm and off-peak margins (Exhs. HO-PL-22, HO-RR-30). In its second revision, the Company also fine-tuned its methodology for calculating off-peak sales and analyzed the effect of a $0.25 per Mcf interruptible margin, which it argued was more representative of the margins it was likely to receive than was its planning margin of $0.15 per Mcf (Exh. HO-RR-30).

over base, high and low demand forecasts,[126] low, mid, and high interruptible margins, 15 and 30 year time frames, and base, low, and high gas costs (id.). The Company also provided an analysis of the cost effects of firm and interruptible transportation for the PennEast volumes (id.).

Boston Gas Company noted that, in this analysis, Scenario 2 (take the PennEast increment, eliminate ANE, use interruptible transportation) outperformed Scenario 6 (take the PennEast increment, retain 7 MMcf per day of ANE, use interruptible transportation) (id.).[127] However, the Company asserted that the non-price benefits of Scenario 6 outweighed the monetary benefits of Scenario 2, and that net benefits to ratepayers therefore remained higher under Scenario 6 (id.).

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125/ At the Department's request, the Company provided five cost analyses relating to its ANE volumes. These included (1) an analysis of the average rate impact of 8.6 MMcf/day of ANE over the life of the ANE contract, based on the Company's June, 1991 demand forecast (Exh. DPU 1-2); (2) a similar analysis extending to the year 2019 (Exh. DPU-14); (3) an analysis of the net benefits of a conservation resource which provided the same level of peak period volumes as the ANE volumes (Exh. DPU-15); (4) an analysis of the net benefits of a ten year conservation program together with the ANE volumes (Exh. DPU-16); and (5) an analysis of the social net benefits of the ANE volumes, taking into account the environmental externalities of the oil and electricity which the ANE volumes would displace (Exh. DPU-13). The Company asserted that, although its analyses show that the addition of ANE volumes would result in net financial costs to its customers, the non-price benefits of the ANE volumes outweigh these costs (Tr. 8, pp. 80, 83, 84).

126/ The Company indicated that its low demand forecast was its base demand forecast less the savings projected to result from existing and proposed conservation programs (Exh. HO-PL-22).

127/ In its brief, the Company argued that the cost analysis demonstrated that Scenario 6 outperformed Scenario 2. However, an examination of the brief shows that it refers to an earlier version of the cost study, which included some double-counting of the interruptible margin (Brief, pp. 14-16).

iii. Analysis

In the 1990 Boston Gas Decision, the Siting Council articulated detailed standards of analysis for major new supply acquisitions in Orders 10 and B. In Sections III.F.2 and III.F.5, below, the Siting Council considers whether Boston Gas complied with these standards in evaluating its ANE/PennEast volumes. Here, we consider whether the Company has properly applied its planning process in making the ANE/PennEast decision, and whether the addition of the PennEast volumes, and the retention of seven MMcf/day of the ANE volumes, each contribute to a least cost supply plan.

As discussed in Section III.D, above, Boston Gas has taken steps to improve its supply planning process, and we are confident that the Company's IRM process can, when properly applied, lead to least cost supply decisions. However, the Siting Council sees three fundamental flaws with the application of that planning process to the ANE/PennEast decision.

First, in making its ANE/PennEast decision, the Company failed to account for Company-sponsored C&LM, either as an alternate supply resource or as a contingency which might lower its demand forecast. The Siting Council notes that the Company filed for Department approval of its residential C&LM plan in June of 1990, and therefore had available to it detailed information on residential conservation resources with costs lower than that of the ANE volumes. The Siting Council acknowledges some uncertainty about the size and reliability of conservation resources available to gas companies; however, at a minimum, the Company's base case demand scenario should have incorporated a likely level of Company-sponsored conservation programs. Quite simply, it is inconsistent for gas companies to sponsor large conservation programs while assuming zero percent effectiveness of these programs for supply planning purposes. Further, since the ANE volumes are relatively small, and since Boston Gas is implementing an aggressive conservation program, the omission of planned conservation resources from this analysis has a significant impact on the perceived need for the ANE volumes. This, in turn, results in a potentially significant underestimate of the cost to Boston Gas ratepayers of retaining the ANE volumes.

The Siting Council's second, related, concern is that the Company did not consider a low demand scenario in making its decision. Clearly, a balanced analysis must consider the contingencies which result in lower than forecasted demand, as well as those which result in higher demand. As we have noted above, Boston Gas had, at the time of its decision, filed a major residential conservation program with the Department. In addition, at that same time, the Massachusetts economy showed clear signs of weakening. Further, the Company's demand forecast included substantial growth in new markets, such as gas air-conditioning and cogeneration, which the Company had little experience in forecasting. The lack of a low-demand scenario incorporating some combination of slow economic growth, successful DSM efforts, and slower-than-expected penetration of new markets, is a serious flaw in the Company's analysis.[128]

While the Siting Council fully supports scenario analysis as a basis for supply planning decisions, we note that it is valuable only when a company evaluates a complete range of

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128/ The Siting Council notes that the Company's most recent demand forecast is lower than the forecast on which the ANE/PennEast decision was based, and that the ANE volumes will likely not be needed to meet demand until 1998/99, rather than in 1996/97, as originally forecasted (Exh. HO-FS-13). Additionally, the Siting Council notes that the Company has received Department approval for conservation programs which provide greater peak period volumes than ANE (Exh. DPU-1-5). The Company used its ANE volumes as the avoided cost for these programs; therefore, by definition, its conservation programs are a lower cost way to meet this demand than is ANE. The Siting Council recognizes that these facts were not available to the Company at the time of its decision, and therefore have not been considered in our analysis, above. However, we note that these outcomes demonstrate the need for companies to analyze a low demand case.

possible scenarios. By omitting a low-demand scenario, which would have been less favorable towards the acquisition of new volumes, Boston Gas skewed its analysis in favor of retaining the ANE volumes. In retrospect, it is apparent that many of the conditions which the Company should have modelled in a low-demand case -- relatively slow economic growth, a delay in the development of the cogeneration market, the approval of aggressive C&LM programs -- have in fact developed. Had Boston Gas evaluated a more balanced range of cases, it could have considered the costs which the ANE increment would impose on its ratepayers in unfavorable circumstances, as well as the benefits which accrue under favorable circumstances.

The Siting Council's third concern is the lack of any direct analysis of risks and benefits to the Company and ratepayers. In its analysis, Boston Gas carefully defined the ratepayer benefits of retaining the ANE volumes under the base demand forecast. However, since the Company did not analyze a scenario in which the expected demand did not materialize, it could not quantify the risks associated with retaining the ANE volumes and determine whether they were acceptable in light of the benefits. Instead, the Company simply asserted that it would be able to create a market for its new volumes if the expected markets do not develop, an assertion which the Siting Council has some difficulty accepting.

This omission is especially critical in this analysis because a significant portion of the Company's expected load growth was in the large-scale cogeneration market. Since cogeneration projects are very large relative to other gas customers, the loss or delay of a single project can have a significant effect on the year in which a new supply is needed, and therefore on the costs or benefits of that supply to ratepayers. Without some analysis of whether the benefits to ratepayers under favorable circumstances outweigh the clear risks if a cogeneration project is delayed, it is difficult to properly evaluate the appropriateness of the Company's ANE/PennEast decision.

These three flaws seriously undermine the Company's analysis. The Siting Council notes that, in the 1990 Boston Gas Decision, issued in February, 1990, we put Boston Gas and other gas companies on notice that planned and expected conservation resources must be considered in supply planning, and that a risk/benefit analysis was a mandatory part of any decision to acquire new supplies. The Company failed to incorporate these considerations in its cost analysis of the ANE/PennEast decision. The result is a cost study obviously skewed in favor of a larger supply portfolio. Consequently, the Siting Council finds that, in making its decision on the ANE volumes and the PennEast increment, Boston Gas failed to properly apply its planning process.

Because Boston Gas did not, at the time of its decision, apply an appropriate decision-making process, the Siting Council requested an additional study incorporating a low demand forecast and additional sensitivity analyses. This additional study allows the Siting Council to consider whether the Company has demonstrated (1) that the substitution of 10 MMcf/day of PennEast for 10 MMcf/day of ANE contributes to a least cost supply plan, and (2) that the retention of seven MMcf/day of ANE contributes to a least cost supply plan.[129]

The Siting Council first notes that Boston Gas has clearly demonstrated that using interruptible transportation for whatever PennEast volumes are taken results in sizable financial savings. The Company has indicated that interruptible transportation on Algonquin is available for most of the year, and that it can convert its interruptible transportation to firm transportation with 18 months notice. Consequently, interruptible PennEast

129/ The Siting Council here reviews the cost study presented in Exh. HO-RR-30, which corrects earlier inaccuracies in the calculation of interruptible sales.

volumes are clearly preferable to firm PennEast volumes in this instance.

The Siting Council also notes that the revised cost analysis demonstrates that Scenario 2 (take 10 MMcf/day PennEast, eliminate ANE) and Scenario 6 (take 10 MMcf/day PennEast, reduce ANE to 7 MMcf/day) generally provide the greatest financial benefits to ratepayers over the 14 demand/interruptible margin cases examined as part of the analysis. Both scenarios offer substantial gas cost savings and substantial net benefits to ratepayers over the base case in which the Company took 17 MMcf/day of ANE and no PennEast increment.[130] In both scenarios, the Company takes the PennEast increment and reduces its ANE take by at least 10 MMcf/day. Consequently, the Siting Council finds that the substitution of 10 MMcf/day of PennEast for 10 MMcf/day of ANE contributes to a least cost supply plan.

The remaining issue is the Company's retention of 7 MMcf/day of the ANE volumes, as assumed in Scenario 6.[131] The revised cost study analyzes the net benefits of Scenarios 2 and 6 over a total of 14 demand/interruptible margin cases. Under this analysis, Scenario 2 provided higher net benefits than Scenario 6 in seven cases, while Scenario 6 provided higher net benefits than Scenario 2 in three cases; in four cases, the net benefits were very similar.[132]

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130/ The Siting Council notes that, in this analysis, Boston Gas also considered a scenario in which it eliminated the ANE volumes and did not replace them with the PennEast increment. This scenario performed poorly over the 14 demand/interruptible margin cases.

131/ The Siting Council notes that the Company actually retained 8.6 MMcf per day of the ANE volumes.

132/ Of the analyses performed over 30 years, Scenario 2 provided greater net benefits in the base demand/low margin, low demand/low margin, and low demand/mid margin cases; Scenario 6 provided greater net benefits in the base demand/high margin and high demand/high margin cases; and net benefits were relatively similar in the base demand/mid margin, high demand/mid margin, The Siting Council notes that, for all levels of demand, the retention of the ANE increment results in higher overall gas costs. Further, the revenues provided by new customers outweigh these higher costs only in cases where the profits from sales to interruptible customers are assumed to be well above both the profits usually assumed by the Company for planning purposes and the profits the Company has recently received. Further, while the possible benefits to ratepayers of retaining ANE are only $2.5 million over 30 years even under the most optimistic scenario, the cost of retaining ANE ranged up to $5.1 million over 30 years, or $7 million if the analysis were done over the 15-year life of the contract.[133] The Siting Council notes that the low demand case used in this analysis did not reflect either a delay in large-scale cogeneration development or a slow-down in the Massachusetts economy; consideration of these possibilities likely would have substantially increased the estimated costs of retaining the ANE volumes.[134] Consequently, the revenue analysis

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high demand/low margin, and low demand/high margin cases. Scenario 2 provided higher benefits in both cases where a 15 year time frame for analysis was used, and in two out of three cost sensitivity cases.

In comparison to the base case scenario, the impact of Scenarios 1 through 9 on net benefits to ratepayers ranged from a loss of $10.3 million to a gain of $58.9 million (Exh. HO-RR-30). For the purpose of evaluating this analysis, the Siting Council assumes that the benefits of Scenarios 2 and 6 are roughly equal when they differ by less than $1 million.

133/ These results were obtained by comparing the benefits of Scenarios 2 and 6 for the following cases: high demand/high margin, low demand/low margin, and base demand/low margin/15 year analysis (Exh. HO-RR-30, Attachment 1, Tables 1, 2a, and 3).

134/ The Siting Council notes that a similar analysis prepared for the Department assuming the Company's current demand forecast shows a cost to ratepayers of approximately $11.9 million over the life of the contract, or approximately $9.1 million over a 30-year period of analysis (Exh. DPU-14). In this analysis, customer rates are higher than they would have been without the contract until the year 2002 (id.).

clearly indicates that the elimination of the ANE volumes provides greater financial benefits over a wider range of possible futures than does the retention of the ANE volumes.

In addressing the results of this revenue analysis, Boston Gas acknowledged that Scenario 2, in which ANE is completely eliminated, provides somewhat greater financial benefits than Scenario 6, in which 7 MMcf/day of ANE was retained. However, the Company argued that the non-price benefits of Scenario 6 outweigh the financial benefits of Scenario 2. The Siting Council therefore considers whether the non-price factors cited by the Company in favor of retaining some ANE volumes -- volume and price flexibility, diversity of suppliers, a new take station, and political implications -- outweigh the financial benefits of eliminating them.

Volume and price flexibility and diversity of suppliers are valuable because they allow the Company to meet its sendout requirements at a lower cost under certain contingencies. However, the Company's cost study indicates that the retention of 7 MMcf/day of ANE raises overall gas costs. The Company has not offered evidence that ANE's volume and price flexibility reduce its expected cost of gas enough to offset the overall gas cost increase. In addition, the Siting Council notes that, in any case, Boston Gas has significant volume flexibility from sources such as Tennessee and Algonquin, and that the Company has stated that it intends to take its full volumes of ANE every day. Since the Company does not intend to use the volume flexibility provided by ANE, the value of that flexibility to the Company and its ratepayers appears minimal.

Similarly, a new take station adds value in that it allows the Company to take advantage of price differences between Tennessee and Algonquin. However, the Company has not offered an estimate of the potential savings resulting from this added flexibility. Further, the Siting Council notes that, for most of the year, the Company has substantial excess capacity and receipt points on both pipelines, and should be able to take advantage of price differentials with or without a new take station.

Finally, the Company has argued that its complete withdrawal from the ANE project could have resulted in a denial of project financing, which would have hurt other Massachusetts LDCs. The Company also suggested that the failure of the ANE project might have led to the collapse of the Iroquois project, on which the Company depends for delivery of its Esso volumes. The Company asserted that these failures would significantly affect both the adequacy and cost of their own supply portfolio, as well as the supplies of other Massachusetts LDCs.

The Siting Council recognizes and supports the benefits of additional regional pipeline capacity and supplies both to individual utilities and to the Commonwealth. The Siting Council also recognizes the difficulties and length of time associated with the development of new interstate pipeline projects, including the acquisition of necessary permits and project financing. The loss of either the ANE project or the Iroquois pipeline would clearly have significant detrimental impacts, both for Boston Gas customers and for the rest of the state. The Siting Council further notes that new regional capacity and gas supplies are especially important in light of recent changes in the gas industry and the increasing role which gas may play in the Commonwealth in response to the 1990 Clean Air Act Amendments and other regulatory actions. Therefore, the Siting Council accepts that it was appropriate for Boston Gas to consider the effects of a complete withdrawal from the ANE project on both the project and the Iroquois pipeline in making its decision to retain some ANE volumes.

However, the Company has provided no documentation in support of its assertion that its complete withdrawal from the ANE project could jeopardize both the project and the Iroquois pipeline. The Siting Council acknowledges that, if the potential impact on these projects was real, the benefits of remaining in the project at a low level would clearly outweigh the costs to Boston Gas' customers and that the Company's retention of the ANE volumes may in fact have been an appropriate decision. However, since the record does not contain sufficient information to allow the Siting Council to evaluate the Company's assertions, the Siting Council can make no finding as to whether this non-price benefit outweighs the financial costs to Boston Gas ratepayers of retaining seven MMcf/day of the ANE volumes. Consequently, the Siting Council makes no finding as to whether the retention of seven MMcf/day of the ANE volumes contributes to a least cost supply plan.

The Siting Council notes that the Company originally intended its discussion of the non-price benefits of the ANE volumes to strengthen a decision based primarily on financial analysis, rather than to play a determining role in that decision. While the Siting Council has required companies to consider non-price criteria in making supply decision, the burden on the Company to define the size of the non-price benefits of a resource is clearly greater when these benefits offset financial costs rather than add to existing financial benefits. In the future, where the Company seeks to justify supply decisions under similar circumstances, it will be expected to provide significantly more comprehensive analysis and justification of the value assigned to the non-price criteria.

b. Response to Tennessee Cosmic Settlement

i. Application of the Supply Planning Process

During the course of this proceeding, Boston Gas informed the Siting Council of its intention to convert 47,000 MMBtu/day of its Tennessee CD-6 sales contract to firm transportation and to purchase replacement volumes directly from five gas producers (Exh. BGC-11). The Company indicated that it developed its conversion plans in response to a settlement between the

Tennessee pipeline and its customers which included restructuring and comparability of service provisions ("Cosmic Settlement") (id.).[135]

Boston Gas stated that the Cosmic Settlement presented it with three choices: (1) whether or not to unbundle its firm sales service, (2) whether to select a Flexible Capacity Entitlement of 50 percent or 100 percent,[136] and (3) how much of its firm sales service to convert to firm transportation (Exh. HO-PL-28). The Company indicated that, because these were strategic decisions involving the restructuring of existing contracts, they were made primarily by the gas supply planning department, although the IRM Task Force was aware of the issues and approved the decisions (Tr. 5, p. 105).[137] The Company stated that it had no opportunity to reduce its Tennessee capacity as part of the Cosmic Settlement (id., p. 110).

The Company provided a cost study showing that unbundling its existing sales service into sales and storage components provided demand charge savings of approximately $2 million per year (Exh. HO-PL-28, Attachment A). Mr. Gulick indicated that the unbundled service retained the flexibility and reliability of the existing sales service, since the Company received access to

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135/ FERC gave its final approval to the Cosmic Settlement, with modifications, on April 8, 1992.

136/ Flexible Capacity Entitlement ("FCE") is an option which allows a company to chose, on a monthly basis, to use some of its unbundled sales MDQ as firm transportation. An FCE of 50 percent allows the use of 50 percent of MDQ in this way, while an FCE of 100 percent allows the use of up to 100 percent of MDQ (Tr. 5, pp. 96-98; Tr. 6, p. 137). The Company stated that it chose the 100 percent FCE option to maximize its flexibility, and that it believes it will be able to recover the higher demand charge associated with the 100 percent FCE option (Exh. HO-PL-28; Tr. 5, p. 98).

137/ Mr. Gulick noted that conversion at this time allows the Company to select desirable receipt points, which are critical to ensuring access to long-term, reliably-priced supplies (Tr. 6, p. 139).

storage capacity and use of its average daily capacity under the existing service (Tr. 5, p. 95).

Boston Gas stated that it chose its conversion level based on an analysis of the cost and reliability benefits of proposals from suppliers, including Tennessee (Exh. HO-PL-28; Brief, p. 23). The Company also considered it desirable to convert a large volume which could still be taken at a high load factor,[138] in order to exercise market power when negotiating purchase contracts (Brief, p. 23). The Company stated that it issued an RFP to 56 suppliers, and selected a short list of 10 based on reputation, past experience with the Company, strength of supply warranties, price, and price negotiability (Exh. BGC-11, p. 3). These companies, and Tennessee, were further evaluated based on financial strength, supply reserves, and producing ability (id.; Tr 5, p. 101). Based on these considerations, Boston Gas negotiated five direct purchase contracts totalling 47,000 MMBtu/day (Exh. HO-PL-28; Tr. 5, p. 103). Boston Gas stated that one of the Company's primary criteria in selecting suppliers was that each supplier be able to match or exceed Tennessee's level of service (Exh. BGC-11, p. 3).

ii. Analysis

The Siting Council notes that the supply decisions taken in response to the Tennessee Cosmic Settlement involve the restructuring of an existing supply contract, rather than the acquisition of a new supply increment. Consequently, the

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138/ Mr. Gulick stated that the Company chose to convert approximately half of its minimum-day summer requirement, in order to take the third-party volumes at a high load factor, and retain some summer-time volumes to be converted on Algonquin in the future (Tr. 5, pp. 101-102). The Siting Council notes, however, that the Company is also committed to taking its Canadian supplies, totalling 44,637 Mcf/day without ANE, or 52,992 Mcf/day with ANE, at high load factors. This may reduce the high load factor volumes which can be promised to suppliers on the Algonquin pipeline.

Company's analysis appropriately relates primarily to issues involved in the contract restructuring. The Siting Council also notes that the Department will be reviewing the Company's five direct supply contracts. Here, we review the Company's decision to unbundle its sales and storage service and its decision to convert 47,000 MMBtu/day from firm sales to firm transportation.

In deciding to unbundle its services, Boston Gas appropriately considered both costs and the non-price factors of reliability and flexibility. Unbundling provided the Company with cost savings, while allowing the Company to retain a similar level of reliability and flexibility.

Further, in selecting its suppliers and its level of conversion, Boston Gas considered both cost and the non-price criteria of reliability and flexibility. The Company also selected a conversion level which it believed would give it the most market power in negotiating direct purchase agreements.[139] In addition, the Company took into account the strategic advantage of selecting receipt points at this time. Finally, the Company's use of an RFP process to solicit proposals from third party suppliers was an appropriate mechanism to identify and evaluate a broad range of supply alternatives.

Based on the above, the Siting Council finds that the Company properly applied its planning process in making the decision to unbundle its services and in selecting its level of conversion, and that the conversion contributes to a least cost supply plan.

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139/ As discussed in footnote 138, the Company selected a level of conversion which it believed would provide market power, while reserving similar levels of baseload requirements for conversion on Algonquin in the future. A comparison of likely savings due to conversion on Algonquin and on Tennessee might have led the Company to convert more sales volumes to transportation on one pipeline than on the other.

c. Supplemental Storage and Capacity

i. Application of the Supply Planning Process

During this proceeding, Boston Gas has described a series of decisions involving its use of supplemental supplies, primarily LNG. Specifically, the Company decided to shut down one of its LNG storage tanks, to renew an LNG storage contract with Algonquin, and to shut down its SNG production plant in Everett. The Siting Council reviews the Company's decisions here to determine whether the Company properly applied its planning process in making these decisions and whether the decisions contribute to a least cost supply plan.

Boston Gas reported that, in 1992, it will dismantle one of its two LNG storage tanks at Commercial point in Dorchester (Exh. BGC-3, p. 9). The Company noted that the retirement of this tank, which will reduce overall storage capacity by approximately one Bcf, will have no impact on the amount of LNG which the Company can send out on any particular day, because vaporization capacity will remain the same (id., Exh. BGC-1, p. 64; Tr. 5, pp. 124-125).

The Company indicated that its decision to retire the tank was based on cost and the availability of alternative supplies (Exh. BGC-3, p. 9; Tr. 5, pp. 124-125).[140] Mr. Gulick also noted that the decision to retire the tank was consistent with the Company's strategy of reducing reliance on liquid supplies in favor of pipeline gas and underground storage (Tr. 5, p. 125). Mr. Gulick noted that this strategy is based on the Company's perception that LNG and propane are both more expensive and more

140/ The Company noted that operational modifications to its other Commercial Point tank had proven very expensive; therefore, before undertaking similar work on this tank, the Company evaluated the need for the storage, and determined that, due to the availability of additional seasonal storage and pipeline supplies, the tank was no longer needed (Exh. BGC-3, p. 9; Tr. 5, p. 124).

complicated logistically than pipeline and storage options (Tr. 4, pp. 114-115). According to Mr. Gulick, the decision to dismantle the tank was made primarily by senior management in the Gas Supply Department, with the cooperation of the IRM Task Force (Tr. 5, p. 125).

Boston Gas also indicated that it intended to renew its ST-LG contract with Algonquin, which provides the Company with up to 400 MMcf of LNG storage in Providence, Rhode Island, for a period of two years (Exh. HO-FS-9; Tr. 4, p. 120). The Company stated that the LNG available under the contract would displace propane during a design winter in 1991-92 (Tr. 4, p. 120). The Company indicated that it chose to renew the contract based on a comparison of the cost of maintaining the contract with the cost of sending out propane (id.).[141]

Boston Gas also reported that it had decided to retire its SNG plant in Everett, which had a capacity of 40 MMcf/day (Exh. BGC-11, p. 4). The Company indicated that the plant technology is outdated, and that, in developing its capital budget, it determined that the costs of maintaining the plant outweighed the benefits provided by it (id.; Tr. 5, p. 120).[142] Furthermore, the Company did not expect to rely on the output of the SNG plant for either normal or design sendout at any time during the forecast period (Exh. BGC-1, Tables G-22N and G-22D).

#### ii. Analysis

The Siting Council has found above that it is appropriate for Boston Gas Company to make simple, relatively minor supply

141/ The Company stated that it did not have the option of requesting a one-year extension of the contract (Tr. 4, p. 120).

142/ Mr. Gulick stated that the Company did not perform a detailed cost analysis of this decision, since it was aware that the gas produced by the SNG plant is substantially more expensive than other supply alternatives (Tr. 5, p. 120).

decisions in its Gas Supply Department, without the formal involvement of the Company's IRM Task Force, so long as consistent price and non-price criteria are considered, and the decisions are integrated with those from the IRM process (see Section III.D.2.b.ii). In making these supplemental supply decisions, the Company has focussed primarily on price and operational considerations. The Siting Council considers these to be generally appropriate criteria for these particular supply decisions. Consequently, the Siting Council finds that the Company has properly applied its planning process in making these decisions and that these decisions contribute to a least cost supply plan.

However, the Siting Council notes that the resource decisions discussed here support a strategy of reducing reliance on liquid supplies in favor of pipeline supplies and underground storage. In future filings, to the extent that the Company continues to pursue this policy, it should discuss the circumstances under which such a strategy contributes to a least-cost supply portfolio, and how it supports the Company's goal of a flexible and diverse supply portfolio.

The Siting Council also notes that the Company found need for one LNG storage option -- the Algonquin ST-LG contract -- but not for a second -- the Commercial Point LNG tank -- without directly comparing the two options. There are obvious differences in size, cost, and timing between the two options which presumably account for the decision to accept the one and reject the other. In the future, however, when considering similar resources, the Company should describe its reasons for choosing one over the other.

Finally, the Siting Council notes that, since the Algonquin contract is needed only in the case of a design winter, the cost of the contract should be compared with the cost of sending out propane reduced to reflect the low probability of design winter occurrence, not with the full cost of sending out propane. It is not clear from the record which comparison the Company made. We note that, as a general rule, supply decisions should lead to a portfolio which meets a normal year in the least-cost manner; supply decisions which raise the cost of gas in a normal year in order to reduce costs in a design year must be carefully evaluated.

d. Conservation and Load Management

i. Application of the Supply Planning Process

As stated in Section III.B.4, above, the DPU approved the Company's Residential Water Heating, Residential Attic Insulation, Residential Home Heating, and Multifamily Energy Savings programs in DPU 90-55.[143] These programs will be implemented over a five-year period from 1991 through 1995 (Tr. 5, p. 170). The Department also approved a Commercial/Industrial program on January 13, 1992. DPU 90-320, at 119-121. The Company plans to implement the C&I program over a four-year period, with the first two years serving as a "ramp-up" period. DPU 90-320, at 1. Finally, the Company stated that its proposed Residential High-Use Customer Program and its Residential High-Efficiency Furnace Replacement Program were filed with the DPU in February, 1991 (Tr. 5, p. 169). The review of those programs is still pending (id.).[144]

Boston Gas selected the C&LM resources incorporated in these programs by using a societal cost test which compared the cost of each C&LM measure to the Company's avoided costs, plus monetized externalities (Exh. BGC-1, p. 69). The Company

143/ The DPU issued its order in DPU 90-55 on September 28, 1990. The Company began implementing its residential conservation programs in the field shortly after that time (Exh. HO-RR-20, p. 6).

144/ The DPU has docketed this review as DPU 91-29.

determined the annualized energy savings and cost estimates for its C&LM programs and presented them to the DPU (Exh. DSM-1).

Boston Gas indicated that the cost estimates were prepared by EII as part of its technical potential study (Exh. HO-DSM-2). The Company also included environmental externalities in its final calculation of the costs and benefits of each conservation measure. DPU 90-55, at 117. In DPU 90-55, the DPU found that the Company's externality values were reasonable, but ordered the Company to use the DPU's externality values in all future filings. Id., at 132. Further, in DPU 90-320, the DPU found the Company's application of environmental externalities to its C&I conservation programs to be appropriate and consistent with the DPU's findings in DPU 89-239.[145]

The Company's estimated energy savings were derived by estimating the savings potential of the identified conservation programs multiplied by the number of customers targeted by the Company for conservation measures (Tr. 5, p. 175). However, Boston Gas indicated that it was concerned that the energy audit savings data used in the EII technical potential study might overstate the actual potential C&LM energy savings (id.). Therefore, with the exception of a few conservation measures, Boston Gas discounted the estimated savings to reach what the Company believed to be a more realistic projection of the energy savings to be achieved by its proposed measures (Tr. 5, p. 158). Ms. Greenblatt testified that Boston Gas reviewed and discounted each conservation measure individually (Tr. 5, p. 159). Boston Gas indicated that this discounting is meant to take into account factors, such as customer behavior, improper equipment installation, and failure of materials, which could affect the

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145/ DPU 89-239 (1990), Integrated Resource Management Practices for Electric Companies, issued August 31, 1990, is the DPU's generic order on integrated resource management for electric utilities. In that order, the DPU provided monetized estimates of the environmental costs resulting from the emission of various pollutants. DPU 89-239, Table 1.

actual amount of energy savings. DPU 90-55, at 116. The Company's discount factors for residential programs ranged from 10 percent for attic insulation to 50 percent for clock thermostats and from zero percent to 50 percent for C&I measures. Id.; see DPU 90-320, at 27. The DPU approved the use of both the residential and C&I discount factors (Exh. HO-DSM-2; also, see DPU 90-55, at 119-120, DPU 90-320, at 27).

After discounting estimated conservation savings and adding administrative costs to the cost of each measure, the Company determined which measures would be cost-effective if installed alone in a facility. DPU 90-320, at 37. Once the maximum stand-alone savings potential of each measure was determined, the Company used an iterative computer model to calculate overall savings potential after accounting for the interactive effects of a number of conservation measures installed together at one facility. Id., at 38.[146] The Department approved the use of this model to calculate the savings attributable to a bundle of measures. DPU 90-55 at 124; DPU 90-320 at 40.

In designing its residential and C&I conservation programs, the Company updated an avoided cost study initially approved by the DPU in Boston Gas Company, DPU 88-67, Phase II (1988).[147] The Company used as its avoided unit a supply block

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146/ According to the Company, interactive effects result when bundles of DSM measures are implemented on the same site (Exh. HO-DSM-2). Boston Gas stated that when DSM measures interact with each other, the effect of implementing the first measure will reduce the maximum stand-alone savings potential of the second, and subsequent measures (id.). The Company conducted multiple iterations to develop a bundle of DSM technologies, by customer sector and end-use, with the greatest net value to society (id.).

147/ An avoided cost study includes estimates of the following costs: (1) avoided production capacity costs, (2) avoided distribution capacity costs, and (3) avoided commodity costs. See DPU 90-320 at 24.

including both the ANE volumes and the Esso volumes. DPU 90-320 at 25.[148] The DPU concluded that the Company's revisions to its avoided cost study were reasonable, and that the revised avoided cost estimates are appropriate for purposes of measuring the benefits of gas savings through conservation. DPU 90-320 at 26.

Boston Gas indicated that it established targets for its C&LM programs based on the potential remaining market for the Company's conservation measures (Tr. 5, pp. 163-164). The Company targeted 50 percent of the population for the residential and multifamily programs, and 40 percent of the remaining market potential in the commercial/industrial sector (id., p. 164). Ms. Greenblatt stated that the 50 percent figure for the residential sector represented the Company's estimate of the penetration which could be achieved over a five-year period (id., p. 166). Ms. Greenblatt further stated that the DPU found this estimate to be a reasonable one (id.). The DPU concluded that the Company's proposed 40 percent penetration target for the C&I sector is reasonable for general planning purposes, but noted that, as the Company gains more information on program costs and benefits and on the remaining market, the Company should adjust its target "in order to obtain the optimal level of C&LM savings that would provide the maximum net benefits to existing ratepayers." DPU 90-320 at 21.

Ms. Greenblatt indicated that, in designing its current conservation programs, Boston Gas did not perform an analysis of non-price factors because there was "no data available" at the time to analyze such criteria (Tr. 5, p. 168). However, Ms. Greenblatt stated that the results of the GEMS evaluation and monitoring project should provide the Company with information

148/ The Company used both the Esso and ANE volumes as avoided supplies, despite the fact that the DPU had already approved the Esso supply. See Boston Gas Company, DPU 89-180 (1990). This approach was taken because the DPU requires that a supply decrement used in an avoided cost study should be at least five percent of the Company's peak day load (220 CMR 8.05).

about the non-price attributes of various conservation technologies, as well as cost and savings information (id., pp. 168-169).

ii. Analysis

As stated in Section III.E.1, above, a gas company must demonstrate that the application of its supply planning process, including adequate consideration of C&LM and consideration of all options on an equal footing, has resulted in the addition of resources that contribute to a least-cost supply plan. The Siting Council has consistently held that C&LM programs are not exempt from the Siting Council's requirements under the 1986 Gas Generic Order that a gas company must show that it has completed a comprehensive cost study comparing the costs of a reasonable range of practical supply alternatives in its analysis of major new supply options. 1991 Colonial Gas Decision, 23 DOMSC at 431; 1986 Gas Generic Order, 14 DOMSC 95, at 102. The Siting Council has previously found that an avoided cost study is an appropriate means of satisfying its requirement that a Company compare the cost of conservation programs with the cost of a reasonable range of supply alternatives. 1990 Boston Gas Decision, 19 DOMSC at 458-459.

In its evaluation of its conservation programs, Boston Gas has presented extensive cost/benefit analyses based on the Company's avoided costs and territory-specific savings data. The DPU has found that the Company's revisions to its avoided cost study were reasonable, and that Boston Gas' revised avoided cost estimates were appropriate.

However, the Siting Council also notes that Boston Gas discounted the savings estimates used in its cost/benefit study. In a recent decision, the Siting Council stated that such discounting may be appropriate to ensure that the projected benefits from proposed conservation programs are not overstated, but that gas companies generally should not discount estimates of conservation savings unless they can document that the methodology used to derive those estimates biases the results upward. 1991 Colonial Gas Decision, 23 DOMSC at 430-431. Here, the Company has developed individual discount factors for each conservation measure based on industry studies containing empirical data (Tr. 5, pp. 159-160; DPU 90-55 at 118-119). While we accept the Company's discounting methods for the purposes of this review, the Siting Council notes that the GEMS study should provide Boston Gas with accurate, unbiased information on conservation savings, which will not require discounting.

In addition, in DPU 90-320 the DPU found that the Company's market penetration targets based on a percentage of remaining potential were reasonable for planning purposes, but noted that these targets should be adjusted as the Company obtains more information. The Siting Council notes that, in setting DSM targets, the Company should also consider projected demand and the size of the avoidable resource, to ensure that the Company provides a least cost resource mix to its customers.

The Siting Council notes that, while Boston Gas' IRM process requires consideration of non-price criteria when evaluating conservation resources, the Company does not appear to have considered non-price criteria to any significant degree in its C&LM decisions to date. The Company has included monetized environmental externalities in its cost-benefit calculations. This is a significant first step towards a process which incorporates non-price criteria into decisions concerning conservation programs. (1991 Colonial Gas Decision, 23 DOMSC at 407). However, the Company must take additional steps to ensure that other important non-price criteria are fully considered both in comparing C&LM options to each other, and in comparing C&LM resources with supply-side resources. In order for the Siting Council to find that the Company's conservation programs contribute to a least cost supply plan in its next filing, Boston Gas must provide a detailed description of the non-price criteria considered and how each one was evaluated in developing the Company's conservation programs.

Despite this criticism, the Siting Council finds that, on balance, the Company has established that it has properly applied its planning process in developing its conservation programs, and that these programs will contribute to a least-cost supply plan.

3. Conclusions on Least Cost Supply

The Siting Council has found that Boston Gas properly applied its supply planning process in reaching decisions regarding its level of conversion on the Tennessee system in response to the Tennessee Cosmic Settlement, its acquisition of C&LM resources, and a variety of capital and short term decisions. The Siting Council has also found that each of these supply decisions contributes to a least cost supply plan. The Siting Council has also found that Boston Gas failed to properly apply its supply planning process in making its decision on the ANE volumes and the PennEast increment. Additionally, the Siting Council has found that the substitution of 10 MMcf/day of PennEast for 10 MMcf/day of ANE contributes to a least cost supply plan. Finally, the Siting Council has made no finding as to whether the retention of seven MMcf/day of the ANE volumes contributes to a least cost supply plan.

Boston Gas has gone to considerable lengths to address the criticisms contained in the previous decision regarding the Company's application of its supply planning process. Specifically, the Company undertook a detailed cost analysis of its ANE/PennEast decision, and has provided a discussion of the non-price considerations contributing to that decision. Further, the Company has provided detailed information on the cost and non-price factors involved in its other supply decisions.

Nevertheless, the Siting Council has four remaining concerns regarding the Company's implementation of its supply planning process. The first pertains to the range of sensitivity analyses which the Company performs as part of its cost studies. Gas companies must evaluate a decision's sensitivity to a full range of assumptions, not just those assumptions which they consider most likely. The Siting Council notes that Boston Gas will be acquiring software which will make sensitivity analysis easier; the Siting Council expects that this will lead to a greater breadth of sensitivity analysis in future supply decisions.

Second, the Company, in its ANE/PennEast analysis, failed to perform a risk/benefit analysis of the type ordered in the previous decision. The Company should expand the sensitivity analysis performed as part of its IRM process to include a comparison of demand forecasts with and without uncertain markets where applicable. Again, the Siting Council expects that the Company's acquisition of tools which simplify the process of analysis will lead to the implementation of this requirement in future analyses.

The Siting Council's third concern relates to the selection of an appropriate level of growth for the Company to pursue. The Siting Council notes that, in its IRM process, the Company uses an analysis of net benefits to ratepayers to compare the value of various resources. This framework includes not only the costs of potential resources, but also the benefits to ratepayers from sales to new customers. To the extent that the Company evaluates supply additions of different sizes, it determines its appropriate level of growth, as well as the least-cost portfolio for meeting that growth.

In the <u>1990 Boston Gas Decision</u>, the Siting Council asked the Company to directly address the issue of meeting avoidable demand when it required gas companies pursuing emerging markets to balance the risks and benefits of meeting new markets (19 DOMSC at 452). The Company has argued that such decisions should not be based entirely on economics. The Company's argument would be stronger, and its analysis clearer, if it first articulated its reasons for choosing to meet a certain level of demand, and then determined the least-cost portfolio which would allow it to do so. The Siting Council recognizes that a single cost analysis may play a major role in determining both the appropriate level of growth and the least-cost supply plan to meet that growth; however, the first decision may involve issues, such as equity, which are not relevant to the second. The Siting Council expects that the Company will address this issue more directly in future filings.

Finally, the Siting Council remains concerned that Boston Gas continues to fail to treat its preapproved conservation programs as committed resources when considering the need for supply-side acquisitions. The continued exclusion of conservation resources from the base case supply plan could lead the Company to overestimate its need for additional resources, and, as a consequence, to purchase unnecessary supplies. The Siting Council notes that the Company, through its GEMS program, will be acquiring savings data which should facilitate the integration of its conservation acquisitions into its supply planning. Therefore, in order for the Siting Council to approve Boston Gas' supply plan in its next filing, the Company must fully incorporate estimated savings from its existing and planned C&LM programs over the forecast period into its base case resource plan and its analyses of adequacy for normal and design conditions.

Despite these criticisms, the Siting Council recognizes the Company's efforts to implement our standards for supply planning as enunciated in Orders 10 and B of the 1990 Boston Gas Decision. The Company has made significant progress in implementing its IRM process. Consequently, the Siting Council finds that, on balance, the Company's supply decisions contribute to a least-cost supply plan. The Siting Council further finds that the Company's overall supply plan minimizes cost.

F. Previous Supply Review

In the 1990 Boston Gas Decision, 19 DOMSC at 461, 464-465, the Siting Council approved Boston Gas's supply plan, and ordered the Company in its next forecast filing:

6. (a) to develop an appropriate set of non-price criteria for C&LM as well as for traditional supply options; (b) to attempt to quantify these criteria to the extent possible; and (c) to present support for the evaluation of those non-price criteria which are not readily subject to quantification ("Order Six");

7. to submit an updated cold snap analysis ("Order Seven");

8. (a) to provide a complete description and analysis demonstrating that under assumed design day conditions the Company can reliably operate its Central District distribution system at pressures above the internal Company standard of 13 to 15 psig up to 22 psig; or (b) to provide a plan to enable the Company to meet its design day requirements without operating above 13 to 15 psig under a reasonable range of supply contingencies which includes an analysis of the limitations that such a plan would place on the Company's ability to use all of its vaporizers simultaneously and at full capacity at its Commercial Point LNG facility ("Order Eight");

9. (a) to provide a complete description and analysis of the reason or reasons for not planning reinforcements for the Central District in light of operating constraints in this part of its distribution system; and (b) if reinforcements are planned, to provide an itemized list of such reinforcements and an explanation of their expected impact on such operating constraints ("Order Nine");

10. (a) to provide complete documentation and analysis demonstrating that the Company has compared the ANE/Esso volumes with a reasonable range of supply alternatives, including conservation and load management and supplemental gas supplies; (b) to provide full documentation of the role of non-price criteria in the application of its supply planning process to these volumes; (c) to provide an updated cost study based on (1) assumptions which are fully

consistent with those contained in the remainder of the filing, particularly the projected resources and requirements tables, and (2) a time frame based on the length of the gas supply and transportation agreements or some other appropriate time frame; (d) to provide a study of the sensitivity of the results of the updated cost analysis to changes in the major assumptions underlying the analysis; (e) to provide a description and analysis showing how the Company determined its level of participation (MDQ and ACQ) in the planned supply project; (f) to provide a more detailed discussion of the Company's contingency plans should the markets for these volumes fail to materialize as expected; and (g) to provide a detailed discussion of how the Company has balanced the potential risks and benefits of serving the targeted markets for these volumes ("Order Ten");

11. (a) to quantify the savings of its existing and planned conservation programs over the forecast period; and (b) to fully incorporate these estimates into its base case resource plan and its analyses of adequacy for normal and design conditions ("Order Eleven").

The Siting Council also ordered the Company, in all future filings:[149]

A. to incorporate all planned supplies into its base case resource plan and its analyses of adequacy for normal and design conditions which: (1) have a contractually-specified delivery date within the forecast period under review; or (2) the Company has other reasons to believe may be delivered within the forecast period under review.

B. when large increments of new supplies are added to the Company's supply plan: (1) to establish and fully document that it has compared the proposed supplies to a reasonable range of supply alternatives, including conservation and load management and supplemental gas supplies; (2) to fully document the role of non-price criteria in the application of its supply planning process, as required by the 1986 Gas Generic Order, 14 DOMSC at 100-102; (3) to utilize assumptions in its cost study which are (a) fully consistent with those

149/ These orders were unnumbered in the 1990 Boston Gas Decision; here they are designated Orders A and B for ease of reference.

contained in the applicable sendout forecast and supply plan, particularly the projected resources and requirements tables, and (b) include a time frame based on the length of the gas supply and transportation agreements or some other appropriate time frame; (4) to provide a study of the sensitivity of the results of the cost analysis to changes in the major assumptions underlying the analysis; (5) to provide a description and analysis showing how the Company determined its level of participation (MDQ and ACQ or amount of C&LM) in the planned supply project; (6) to provide a detailed discussion of the Company's contingency plans should the markets for the planned volumes fail to materialize as expected; and (7) to provide a detailed discussion of how the Company has balanced the potential risks and benefits of serving the targeted markets for these volumes. Id., at 465-466.

In Section III.C.3, above, the Siting Council found that Boston Gas has complied with Order Seven. In Section III.C.4, above, the Siting Council found that Boston Gas has minimally complied with Order Eight and has complied with Order Nine. Here, the Siting Council discusses the Company's compliance with the remaining orders.

1. Compliance with Order Six

Part (a) of Order Six required Boston Gas to "develop an appropriate set of non-price criteria for C&LM as well as for traditional supply options" (1990 Boston Gas Decision, 19 DOMSC at 464). Boston Gas stated that it applies a single set of non-price criteria to both demand-side and supply-side resources, although all criteria may not be relevant to every decision (Exh. HO-PL-2). The Company indicated that it had identified two non-price factors, flexibility and diversity of the overall resource portfolio, as attributes which allow the Company to respond to a range of future conditions (Exh. BGC-1, p. 85).[150]

150/ The Company indicated that flexibility included the flexibility of implementation date and operational flexibility, while diversity included diversity of supply type (baseload, intermediate, and peaking), diversity of reliability (firm or

The Company stated that it also considers non-price factors such as operational benefits, regulatory uncertainty, and political implications when making resource decisions, and noted that the importance of such criteria depend on the specific resource being evaluated (id.).

The Siting Council notes that the Company has demonstrated that it has developed a set of non-price factors which can be used to evaluate both traditional supply options and C&LM. Consequently, the Siting Council finds that the Company has complied with part (a) of Order 6.

Part (b) of Order Six required Boston Gas to "attempt to quantify these criteria to the extent possible" (1990 Boston Gas Decision, 19 DOMSC at 464). The Company stated that, wherever useful and possible, it attempted to monetize non-price criteria (Exh. PL-2). However, the Company indicated that the task of valuing most non-price factors was complex, and that it therefore retained DFI to develop a methodology for evaluating these factors (Exh. BGC-1, pp. 85-86). The Company stated that DFI recommended a probabilistic approach in which the Company would: (1) describe the attributes, including non-price attributes such as flexibility and diversity, of each resource option; (2) identify a range of future market and regulatory scenarios; and (3) evaluate the value of each resource under the range of scenarios (id., pp. 86-87). This methodology would implicitly determine the value which non-price attributes, such as flexibility of take and diversity of supplier, bring to the Company's portfolio. The Company indicated that it intends to adopt DFI's recommendations (Tr. 4, p. 14). The Company stated that the DFI model will enhance its ability to evaluate the non-

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interruptible), diversity of resource providers, and diversity of resource duration, renewability, and contract expiration (Exh. HO-PL-14). The Company defined operational flexibility as "flexibility to increase, reduce or cease its takes on an hourly, seasonal, or longer-term basis" (Exh. HO-PL-14).

price factors of demand-side and supply-side resources on an equal footing (Tr. 4, pp. 49-50).

The Siting Council notes that, at this time, the Company has quantified only the environmental externality non-price criterion. However, the Company has made significant progress in developing a framework for valuing other non-price factors, which it intends to use in future filings. Consequently, the Siting Council finds that the Company has complied with part (b) of Order 6.

Part (c) of Order 6 required Boston Gas to "present support for the evaluation of those non-price criteria which are not readily subject to quantification" (1990 Boston Gas Decision, 19 DOMSC at 464). In its discussion of the ANE/PennEast decision and of its response to the Tennessee Cosmic Settlement (see Sections III.E.2.a and b, above), the Company has provided a discussion of its consideration of non-price factors. However, the Company did not directly include a consideration of non-price criteria in its consideration of C&LM resources (see Section III.E.2.d, above). Consequently, the Siting Council finds that the Company has failed to comply with part (c) of Order 6.

Based on the above, the Siting Council finds that, on balance, the Company has minimally complied with Order 6.

2. Compliance with Order 10

a. Compliance with Regard to ANE Volumes

Part (a) of Order 10 required the Company "to provide complete documentation and analysis demonstrating that the Company has compared the ANE/Esso volumes with a reasonable range of supply alternatives, including conservation and load management and supplemental gas supplies." 1990 Boston Gas Decision, 19 DOMSC at 465. The Company evaluated two base load supplies, ANE and PennEast, in comparison with each other (see Section III.E.2.a, above). The Company chose not to consider C&LM as an alternative supply because it felt it did not have sufficient information on the size and reliability of conservation resources. The Company also did not evaluate DOMAC supplies as an alternative, even though these were comparably priced. The Siting Council does not require gas companies to incorporate every supply alternative, however unsuited to the company's need, into every cost study. However, full documentation and analysis requires at a minimum that a company identify the supply alternatives available to it at the time of its decision and indicate why some were not considered in greater detail. The Company failed to do this here. Consequently, the Siting Council finds that the Company has failed to comply with part (a) of Order 10.

Part (b) of Order 10 required the Company "to provide full documentation of the role of non-price criteria in the application of its supply planning process to these volumes." Id. The Company has offered a description of the role which non-price criteria played in this decision. Consequently, the Siting Council finds that the Company has complied with part (b) of Order 10.

Part (c) of Order 10 required the Company "to provide an updated cost study based on (1) assumptions which are fully consistent with those contained in the remainder of the filing, particularly the projected resources and requirements tables, and (2) a time frame based on the length of the gas supply and transportation agreements or some other appropriate time frame." Id. The demand assumptions used in the Company's cost study are not those which appear in the Company's filing. Rather, they are assumptions current at the time of the Company's decision, developed using a methodology which the Siting Council had generally approved in its most recent filing. These are appropriate for evaluating whether the Company's decision, at the time that it was made, contributed to a least cost supply plan.

The time frame of the cost study was based on the sellout date of the supply portfolio[151] plus twenty years. The Company argues that this is an appropriate time frame for analysis, since the Company receives firm sales margins from the load added with the new supply for the life of the new load.[152] The Siting Council notes that there may be some merit to this argument for those cases in which the benefits to ratepayers of the new load flow primarily from firm sales margins, rather than from reductions in the cost of gas. In future cases, however, the Company must defend its assumptions regarding the cost of gas after the end of the contract in more detail if it uses a time frame longer than that of the gas contract.

Based on the above, the Siting Council finds that the Company has minimally complied with part (c) of Order 10.

Part (d) of Order 10 required the Company "to provide a study of the sensitivity of the results of the updated cost analysis to changes in the major assumptions underlying the analysis." Id. In making its decision, the Company considered the sensitivity of its cost analysis to base and high demand cases, and to base and high interruptible margins. In later analyses prepared for the Siting Council, the Company also considered the sensitivity of the analysis to a low demand forecast, a mid-range interruptible margin, low, base and high costs for the ANE volumes, and a time frame the length of the ANE supply contract. The Siting Council finds that the later analyses consider an appropriate range of changes in major assumptions, but that the cost study done at the time of the

151/ The "sellout date" is the last year in which projected firm load can be met without acquiring additional supply resources.

152/ The Company estimates that the life of new heating load is twenty years; therefore, it argues that the benefits of new load should continue for twenty years after the projected sellout date, when the last of the load attributable to the new supply resource is added.

decision was flawed by the omission of a low demand case. Consequently, the Siting Council finds that the Company has minimally complied with part (d) of Order 10.

Part (e) of Order 10 required the Company "to provide a description and analysis showing how the Company determined its level of participation (MDQ and ACQ) in the planned supply project." Id. In its decision process, the Company considered two levels of participation in the ANE project, 7 and 17 MMcf per day; it considered only one level of participation in the PennEast project, because this was the only level offered. The Siting Council finds that the cost study and description of non-price criteria document how the Company chose its level of participation in each project.[153] Consequently, the Siting Council finds that the Company has complied with Part (e) of Order 10.

Part (f) of Order 10 required the Company "to provide a more detailed discussion of the Company's contingency plans should the markets for these volumes fail to materialize as expected." Id. The Company has described mechanisms by which it could transfer its supplies temporarily to a third party, and by which it could stimulate demand for gas in its service territory. The Siting Council notes that some of these opportunities are no longer contingency plans, since the Company is currently pursuing them. Consequently, the Siting Council finds that the Company has minimally complied with part (f) of Order 10.

Part (g) of Order 10 required the Company "to provide a detailed discussion of how the Company has balanced the potential risks and benefits of serving the targeted markets for these volumes." Id. Such an analysis should include an identification

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153/ The Siting Council notes that Boston Gas was unable to transfer a full 10 MMcf/day of the ANE volumes to other gas companies. Consequently, the Company's actual level of participation in the ANE project, 8.6 MMcf/day, is somewhat higher than its optimal choice of 7 MMcf/day.

of the markets served by the new volumes, and a study showing the effects on ratepayers if the projected demand does not develop, or develops more slowly than expected. The analysis should also include an identification of the benefits, to ratepayers and to others, of meeting the load, and a discussion of the extent to which the benefits outweigh the risks. The Company has not, in this record, discussed the tradeoffs of the risks and benefits of serving the markets targeted for these volumes. Consequently, the Siting Council finds that the Company has failed to comply with part (g) of Order 10.

The Siting Council has found that the Company has complied with parts (b) and (e) of Order 10. The Siting Council has also found that the Company has minimally complied with parts (c), (d), and (f) of Order 10, and has failed to comply with parts (a) and (g) of Order 10. Consequently, on balance, the Siting Council finds that the Company has minimally complied with Order 10 in regard to the ANE/PennEast Decision.

b. Compliance with Regard to Esso Volumes

Order 10 also required Boston Gas to conduct a similar analysis with regards to its acquisition of the Esso volumes. The Company stated in its filing that it rested the justification of the Esso supply decision on the record of Boston Gas Company, DPU 89-180, in which the Department approved the Esso purchase contract subsequent to Ch. 164, § 94A (Exh. BGC-1, p. 89). The Company subsequently submitted the record of that proceeding to the Siting Council (Exh. HO-PL-4). The Company indicated that it had chosen to rely on this record, rather than prepare additional analyses for the Siting Council, in the interest of administrative efficiency and consistency, and that the Company believed that the record in the DPU case "materially complies with the Order 10" (Tr. 5, p. 67).

The Company indicated that, according to this record, it considered other Canadian producers and gas marketers as alternatives to the Esso supply, and that it had "taken conservation into account" but had not considered it as a supply alternative due to lack of information (Exh. HO-PL-15). The Company stated that the record also showed that it had considered the non-price criteria of reliability, flexibility, and diversity when making its decision (id.). The Company indicated that the cost study contained in the record was based on an update to the demand forecast approved by the Siting Council in the 1990 Boston Gas Decision, which included an additional 22,932 MMcf of cogeneration load based on letters of intent (Exh. HO-RR-25). The Company also stated that the cost study used the time frame rejected in the 1990 Boston Gas Decision, but argued that such a time frame was appropriate (Exh. HO-PL-17). The Company provided a detailed history of its selection of an appropriate supply increment (Exh. HO-PL-18; Tr. 5, pp. 72-78).

The Company indicated that the record in DPU 89-180 did not directly address the Siting Council requirements for sensitivity analyses, contingency plans, or an analysis of the risks and benefits of serving new markets (Exh. HO-RR-26; Tr. 5, pp. 66-67, 80). However, the Company noted that it had considered various levels of demand in evaluating its commitment to Open Season volumes generally and that its discussion of contingency plans for the ANE volumes could also be applied to the Esso volumes (Exh. HO-RR-26). The Company later provided a discussion of the risks and benefits of acquiring the Esso volumes (id.).

In the record of DPU 89-180, the Company presents an analysis which bears a strong surface resemblance to the analysis rejected in the 1990 Boston Gas Decision. The Company has admitted that it did not consider company-sponsored C&LM as an alternative supply resource,[154] and that it did not reduce the

154/ Mr. Gulick argued that consideration of supplemental resources which were available at the time shows that demand of this magnitude could not have been met with supplemental supplies demand forecast used in its cost analysis to reflect the possible implementation of C&LM.[155] The Company has also admitted that it did not comply with those aspects of Order 10 relating to sensitivity analyses, contingency planning, and risk/benefit analyses.

However, the record shows improvement over the analysis rejected in the 1990 Boston Gas Decision. The cost study is based on a demand forecast, which, although not approved by the Siting Council, was created using a methodology generally approved by the Siting Council.[156] The Company has also provided a detailed discussion of its use of non-price criteria in this decision, and has discussed contingency planning in general.

The Company, in explaining its decision not to perform additional analysis of the Esso volumes, as required by Order 10, has raised the issue of administrative overlap, and has suggested that the record of a Department preapproval case should be sufficient to establish in a Siting Council proceeding that a supply acquisition contributes to a least cost supply plan. However, even where a supply acquisition reviewed by the Siting Council also falls under the jurisdiction of the Department, the two reviews serve different purposes. The Department has clearly articulated this difference in DPU 90-320, noting that the Siting Council reviews each gas company's overall supply planning

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(Tr. 5, pp. 41-42).

155/ Jennifer Miller noted that a data response in the record of DPU 89-190 states that "The net figures reflect predicted load additions after conservation and load loss" (Tr. 5, p. 45). However, in context, this is seen to be a reference to the adjustment of the Company's demand forecast to reflect natural conservation, as described in Section II.D.1, above, rather than an adjustment to reflect company-sponsored C&LM measures (Exh. HO-PL-4, p. 49).

156/ The Siting Council notes, however, that the bulk of the load growth projected in that demand forecast was in the cogeneration sector, and that the Siting Council had not considered or approved that forecast.

process, while the Department reviews incremental resource additions (see DPU 90-320, p. 21). Therefore, the Siting Council may require a more extended analysis than does the Department, so that it can assess a resource acquisition in the context of a company's supply planning process. Within that context, the Siting Council may place greater emphasis on the consideration of supply alternatives and on the effects of demand contingencies than would the Department.

In its 1990 decision, the Siting Council noted its concern that the non-traditional markets for which the Company had in large part acquired the Esso volumes might not emerge as rapidly as the Company projected. This uncertainty in the Company's demand forecast remains of primary concern to the Council. The risk/benefit analysis required in Section (g) of Order 10 was intended to address the risks and benefits of acquiring supplies to serve uncertain markets. The Company has not addressed this issue in the record.

Accordingly, on balance, the Siting Council finds that the Company has failed to comply with Order 10 as it relates to the Esso volumes. The Siting Council notes that this record would not allow it to find that a new resource contributed to a least cost supply plan. However, recognizing that the Company's decision to acquire the Esso volumes was taken several years ago, and that the Department has approved these volumes in DPU 89-180, the Siting Council accepts the Esso volumes as part of the Company's resource portfolio.

### 3. Compliance with Order 11

Part (a) of Order 11 required Boston Gas "to quantify the savings of its existing and planned conservation programs over the forecast period." 1990 Boston Gas Decision, 19 DOMSC at 465.

Boston Gas argues that the GEMS study[157] approved by the DPU in DPU 90-320 complies with Order 11 with respect to the quantification of conservation savings, and "requests that the Siting Council adopt and incorporate the relevant findings of the DPU in DPU 90-320 in this regard" (Exh. BGC-1, p.74).

While the GEMS program is expected to provide more accurate conservation savings data in the future, the Siting Council notes that Boston Gas has already estimated the projected savings of its existing conservation programs over a five year implementation period.[158] (id., pp. 70-72). The Company also estimated the projected savings of its planned conservation programs over a four-year implementation period (id., pp. 72-73). The Siting Council further notes that the Company applied discount factors to its projected savings in order to account for any possible overestimation of these savings (Tr.5, p. 158) (see Section III.E.2.d, above). Therefore, the Siting Council finds that Boston Gas has complied with part (a) of Order 11.

Part (b) of Order 11 required Boston Gas "to fully incorporate these estimates into its base case resource plan and its analyses of adequacy for normal and design conditions." 1990 Boston Gas Decision, 19 DOMSC at 465. The Company did not include the estimated savings from its existing and planned conservation programs in its base case resource plan or in its

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157/ As part of its on-going DSM evaluation, the Company will monitor and evaluate the actual savings potential of DSM technologies through GEMS (Exh. HO-DSM-2). For a more detailed discussion of the GEMS study, see Section III.D.2.c, above.

158/ In the fall of 1989, the Company contracted with an engineering firm to conduct a technical potential study of the energy-savings opportunities within the Company's service territory. The study utilized customer-specific energy audit field data, market research information from the Company's appliance saturation survey, and annual sales data to arrive at an estimate of the overall DSM potential within the Company's service territory. The annualized savings and cost estimates for these DSM programs have been presented to the DPU in three separate proceedings (Exh. HO-DSM-1).

analyses of adequacy for normal and design conditions, arguing that it did not wish to rely on conservation resources to meet sendout until more reliable data as to the magnitude, timing, costs, and market for DSM in its service territory become available (Exh. BGC-1, p. 74). As noted in Section III.D.3, above, the Siting Council has specifically rejected a "wait and see" approach, on the grounds that the exclusion of conservation resources from the base case supply plan could lead the Company to overestimate its need for additional resources, and as a consequence, to purchase unnecessary supplies.

Consequently, the Siting Council finds that Boston Gas has failed to comply with part (b) of Order 11.

4. Compliance with Order A

Order A required Boston Gas to "incorporate all planned supplies into its base case resource plan and its analyses of adequacy for normal and design conditions which: (1) have a contractually-specified delivery date within the forecast period under review; or (2) the Company has other reasons to believe may be delivered within the forecast period under review." 1990 Boston Gas Decision, 19 DOMSC at 465.

The Company has incorporated the ANE and Esso supplies and Steuben Storage into its base case supply plan and its analyses of adequacy for normal and design conditions (Exh. BGC-1, Tables G-22N (Revised), G-22D (Revised), G-22/Backup (Revised), and G-23). However, as noted above, Boston Gas has failed to include its planned and existing conservation programs in both its base case supply plan and its adequacy analysis of normal and design conditions. The conservation programs already approved by the DPU will be implemented during the forecast period and Boston Gas has projected significant savings from these programs during the forecast period. The Siting Council reiterates its position that DSM resources may not be omitted from the Company's base case resource plan. Therefore, the Siting Council finds that the Company has only partially complied with Order A.

5. Compliance with Order B

Order B requires Boston Gas to conduct an analysis similar to that described in Order 10 for each large increment of new supply which the Company added to its supply plan. 1990 Boston Gas Decision, 19 DOMSC at 466. In this filing, the Company has added one such increment, the new PennEast volumes. These volumes were evaluated together with the ANE volumes as described in Section III.E.2.a, above. In Section III.F.2.a, above, the Siting Council found that this analysis only partially complied with Order 10. Consequently, the Siting Council finds that the Company has partially complied with Order B as regards the PennEast volumes.

G. Conclusions on the Supply Plan

In previous sections of this decision, the Siting Council has found that Boston Gas has established that: (1) it has adequate resources to meet its firm sendout requirements throughout the forecast period; (2) its supply planning process is minimally sufficient to enable it to make least-cost supply decisions; and (3) its supply decisions contribute to a least-cost supply plan, and that its supply plan minimizes cost.

Accordingly, the Siting Council hereby APPROVES the 1991 supply plan of Boston Gas Company.

In approving the Company's supply plan, the Siting Council notes the significant progress which the Company has made both in developing an integrated planning process and in implementing that process. The Company has developed standards for analyzing both the cost and non-price implications of its supply decisions, and has undertaken to acquire the tools it needs to implement those standards. Specifically, the Company is acquiring software which will simplify sensitivity analyses and allow it to quantify non-price factors to a greater extent, and has sponsored the GEMS project, which will gather the data needed by all Massachusetts gas companies to properly evaluate their conservation programs.

Nevertheless, the Siting Council has enumerated, above, a number of flaws in Boston Gas' planning processes and in the implementation of these processes. The tools and the data which the Company intends to acquire should allow Boston Gas to address these criticisms. Consequently, the Siting Council fully expects Boston Gas' next filing to address its remaining concerns, and to present a supply plan based on a fully integrated planning process.

IV. DECISION

The Siting Council hereby APPROVES the 1991 sendout forecast and supply plan of Boston Gas Company.

In so deciding, the Siting Council has detailed specific information that Boston Gas must provide in its next filing in order for the Siting Council to approve the Company's next forecast and supply plan. This specific information is necessary for the Siting Council to fulfill its statutory mandate, including its need to determine whether: (1) all information relating to current activities, environmental impact, facilities agreements and energy policies as adopted by the Commonwealth is substantially accurate and complete, (2) the projections of the sendout for natural gas and of the capacities for existing and proposed facilities are based on substantially accurate historical information and reasonable statistical projection methods and include an adequate consideration of conservation and load management and (3) the long-range forecasts are consistent with the policy of providing a necessary, least-cost, minimum environmental impact power supply for the Commonwealth.

Therefore, in order for the Siting Council to approve the Company's next filing, Boston Gas must:

(1) base its planning standards on an up-to-date weather database;

(2) document and justify the electricity price assumptions used in its fuel price forecast;

(3) in its commercial demand forecast, (a) update its energy intensity factors based on data more recent than 1985, (b) provide a more detailed justification of its assumptions on fuel-switching for non-price reasons, (c) reflect mandated appliance efficiency standards in its forecast, and (d) either explicitly forecast the effects

of long-run price changes on energy demand, or explain why it is not appropriate to do so;

(4) in its industrial end use forecast, update the energy intensity and end use distributions upon which the forecast relies, or demonstrate that its old distributions remain reliable;

(5) in its traditional end use demand forecast, include updated comparisons between forecasted and actual load disaggregated by customer class, an analysis of the likely sources of underforecasting, and an action plan for improving the model used;

(6) in its gas air conditioning forecast, provide more persuasive evidence that the ADL curve is applicable to the gas air conditioning market, or develop another, more justifiable, method of estimating market penetration rates for this technology;

(7) in its desiccant dehumidification forecast, provide more persuasive evidence that the ADL curve is applicable to new technologies, or develop another, more justifiable, method of estimating market penetration rates for this technology;

(8) in its natural gas vehicle forecast, provide supporting analysis for its market penetration rates for each vehicle type;

(9) submit base and alternative forecasts of load growth in the power generation market, based on reasonable contingencies, and use these forecasts as a basis for an

analysis of the risks and benefits of planning to meet these loads;

(10) provide a set of alternative sendout forecasts if a particular forecast or forecasts contain uncertainties of significant magnitude;

(11) submit an updated cold-snap analysis;

(12) develop and implement a methodology for recognizing and accounting for the resources provided by existing and planned conservation programs in both its base case supply plan and its supply planning process;

(13) provide a detailed description of the non-price criteria considered and how each one was evaluated in developing the Company's conservation programs;

(14) fully incorporate estimated savings from its existing and planned C&LM programs over the forecast period into its base case resource plan and its analyses of adequacy for normal and design conditions.

The Siting Council notes that the Company's next sendout forecast and supply plan is scheduled to be submitted on November 1, 1993.

Robert W. Ritchie

Robert W. Ritchie
Hearing Officer

Dated this 26th day of June, 1992

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of June 26, 1992 by the members and designees present and voting. Voting for approval of the Tentative Decision as amended: Gloria Larson, Secretary of Consumer Affairs and Business Regulation; Stephen Remen, Commissioner of Energy Resources; Andrew Greene (for Susan Tierney, Secretary of Environmental Affairs); Tom Black (for Stephen Tocco, Secretary of Economic Affairs); Mindy Lubber (Public Environmental Member); and Kenneth Astill, (Public Engineering member).

Gloria C. Larson

Gloria C. Larson
Chairperson

Dated this 26th day of June, 1992

TABLE 1

Boston Gas Company
Forecast of Firm Sendout by Customer Class

Normal Year
(MMcf)[1]

| Customer Class | 1991-1992 Heating Season | 1991-1992 Non-Heating Season | 1995-1996 Heating Season | 1995-1996 Non-Heating Season |
|---|---|---|---|---|
| Res. Heating | 25,594.9 | 11,175.4 | 26,360.5 | 11,255.3 |
| Res. Non-Heat | 1,936.2 | 2,093.9 | 1,846.9 | 1,981.7 |
| Commercial | 15,611.6 | 8,492.9 | 17,945.8 | 9,928.7 |
| Industrial | 3,362.7 | 2,163.4 | 3,558.4 | 2,134.1 |
| Quasi-Firm | 1,498.0 | 7,483.0 | 6,525.0 | 14,201.0 |
| Total Sendout[2] | 52,096.0 | 31,766.0 | 60,916.0 | 39,711.0 |

Design Year
(MMcf)[1]

| Customer Class | 1991-1992 Heating Season | 1991-1992 Non-Heating Season | 1995-1996 Heating Season | 1995-1996 Non-Heating Season |
|---|---|---|---|---|
| Res. Heating | 27,994.4 | 12,260.9 | 28,888.8 | 12,355.3 |
| Res. Non-Heat | 2,120.0 | 2,298.3 | 2,027.8 | 2,212.1 |
| Commercial | 17,109.7 | 9,285.8 | 19,882.2 | 10,774.5 |
| Industrial | 3,723.2 | 2,392.1 | 3,940.3 | 2,369.3 |
| Quasi-Firm | 1,498.0 | 7,483.0 | 6,543.0 | 14,205.0 |
| Total Sendout[2] | 57,494.0 | 32,910.0 | 66,703.0 | 40,902.0 |

Notes:

1. One BBtu is assumed to equal one MMcf.

2. Includes Wakefield sales, company-use, and unaccounted for gas.

Sources: Exh. BGC-1, Tables G-1 to G-5, Revised

TABLE 2A

Boston Gas Company
Base Case Design Year Supply Plan

Heating Season
(BBtu)

| Firm Requirements: | 1991-92 | 1992-93 | 1993-94 | 1994-95 | 1995-96 |
|---|---|---|---|---|---|
| Firm Sendout | 57,494 | 60,729 | 62,026 | 65,771 | 66,703 |
| Interruptible | 0 | 0 | 0 | 0 | 0 |
| Storage Refill | | | | | |
| Underground | 0 | 0 | 0 | 0 | 0 |
| Liquefaction | 400 | 504 | 537 | 482 | 467 |
| TOTAL | 57,894 | 61,233 | 62,564 | 66,253 | 67,170 |
| **Firm Resources:** | | | | | |
| TGP CD-6 | 15,101 | 14,541 | 14,191 | 16,352 | 16,607 |
| TGP Storage Return | 1,861 | 1,861 | 3,010 | 3,010 | 3,010 |
| Esso | 0 | 5,195 | 5,195 | 5,195 | 5,195 |
| ANE | 1,011 | 1,262 | 1,262 | 1,262 | 1,262 |
| Boundary | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 |
| AGT F-1 | 18,750 | 18,599 | 18,465 | 18,818 | 18,837 |
| AGT F-2 | 3,224 | 3,224 | 3,224 | 3,224 | 3,224 |
| AGT F-3 | 963 | 963 | 963 | 963 | 963 |
| AGT WS-1 | 1,985 | 1,624 | 1,804 | 2,331 | 2,496 |
| AGT STB | 3,410 | 3,410 | 3,410 | 3,410 | 3,410 |
| AGT SS-III | 498 | 471 | 511 | 683 | 748 |
| Spot Purchases | 0 | 0 | 0 | 0 | 0 |
| PennEast CDS | 5,139 | 5,134 | 5,121 | 5,139 | 5,139 |
| LNG from Storage | 2,929 | 1,927 | 2,384 | 2,845 | 3,258 |
| LNG Purchase | 1,478 | 1,478 | 1,478 | 1,478 | 1,478 |
| TOTAL | 57,894 | 61,233 | 62,564 | 66,253 | 67,170 |

Sources: Exh. BGC-1, Table G-22D (Revised)

TABLE 2B

Boston Gas Company
Base Case Design Year Supply Plan

Non-Heating Season
(BBtu)

| Firm Requirements: | 1991-92 | 1992-93 | 1993-94 | 1994-95 | 1995-96 |
|---|---|---|---|---|---|
| Firm Sendout | 32,910 | 35,389 | 35,793 | 40,701 | 40,902 |
| Interruptible[1] | 28,580 | 28,580 | 28,580 | 28,580 | 28,580 |
| Storage Refill | | | | | |
| Underground | 6,018 | 5,989 | 7,281 | 7,457 | 7,524 |
| Liquefaction | 3,982 | 2,876 | 3,303 | 3,818 | 4,246 |
| TOTAL | 71,490 | 72,834 | 74,956 | 80,555 | 81,252 |
| **Firm Resources:** | | | | | |
| TGP CD-6 | 19,323 | 19,883 | 20,233 | 18,073 | 17,817 |
| TGP Storage Return | 56 | 56 | 110 | 110 | 110 |
| Esso | 0 | 7,363 | 7,363 | 7,363 | 7,363 |
| ANE | 2,039 | 1,788 | 1,788 | 1,788 | 1,788 |
| Boundary | 2,190 | 2,190 | 2,190 | 2,190 | 2,190 |
| AGT F-1 | 15,556 | 15,707 | 15,841 | 15,488 | 15,469 |
| AGT F-2 | 4,585 | 4,585 | 4,585 | 4,585 | 4,585 |
| AGT F-3 | 1,349 | 1,349 | 1,349 | 1,349 | 1,349 |
| AGT WS-1 | 909 | 1,271 | 1,090 | 563 | 398 |
| AGT STB | 0 | 0 | 0 | 0 | 0 |
| AGT SS-III | 538 | 565 | 525 | 353 | 289 |
| Spot Purchases | 13,689 | 7,516 | 9,290 | 17,432 | 18,369 |
| PennEast CDS | 9,136 | 9,141 | 9,153 | 9,136 | 9,136 |
| LNG Storage Boiloff | 422 | 422 | 422 | 422 | 422 |
| LNG Purchase | 1,698 | 1,000 | 1,019 | 1,704 | 1,968 |
| TOTAL | 71,490 | 72,834 | 74,956 | 80,555 | 81,252 |

Notes:

1. These sales represent the Company's present supply plans. The Siting Council recognizes that actual interruptible sales will vary as available supplies vary.

Source: Exh. BGC-1, Table G-22D (Revised)

TABLE 3

Boston Gas Company
Base Case Design Day Supply Plan

(BBtu)

| Requirements: | 1991-92 | 1992-93 | 1993-94 | 1994-95 | 1995-96 |
|---|---|---|---|---|---|
| Firm Sendout | 749 | 761 | 780 | 794 | 808 |
| Resources: | | | | | |
| TGP CD-6 | 136 | 136 | 136 | 136 | 136 |
| TGP Storage Return | 13 | 13 | 13 | 13 | 13 |
| Esso | 0 | 34 | 34 | 34 | 34 |
| ANE | 8 | 8 | 8 | 8 | 8 |
| Boundary | 10 | 10 | 10 | 10 | 10 |
| AGT F-1 | 127 | 127 | 127 | 127 | 127 |
| AGT F-2 | 21 | 21 | 21 | 21 | 21 |
| AGT F-3 | 6 | 6 | 6 | 6 | 6 |
| AGT WS-1 | 38 | 38 | 38 | 38 | 38 |
| AGT STB | 30 | 30 | 30 | 30 | 30 |
| AGT SS-III | 10 | 10 | 10 | 10 | 10 |
| Spot Purchases | 0 | 0 | 0 | 0 | 0 |
| PennEast CDS | 21 | 21 | 21 | 21 | 21 |
| LNG from Storage | 293 | 293 | 293 | 293 | 293 |
| DOMAC LNG | 101 | 101 | 101 | 101 | 101 |
| Propane from Storage | 70 | 70 | 70 | 70 | 70 |
| TOTAL | 885 | 920 | 920 | 920 | 920 |
| SURPLUS: | 137 | 159 | 140 | 126 | 112 |
| RESERVE: | 18.1% | 20.9% | 17.9% | 15.9% | 13.9% |

Source: Exh. BGC-1, Table G-23 (Revised)

TABLE 4

Boston Gas Company
PennEast/ANE Decision
Scenarios and Cases Evaluated in Original Cost Analysis

<u>Scenarios:</u>

| | |
|---|---|
| Base Case: | 17 BBtu/day ANE, no additional PennEast |
| Scenario 1: | No ANE, 10 additional BBtu/day PennEast (firm transportation) |
| Scenario 2: | No ANE, 10 additional BBtu/day PennEast (interruptible transportation) |
| Scenario 3: | 17 BBtu/day ANE, 10 additional BBtu/day PennEast (interruptible transportation) |
| Scenario 4: | 17 BBtu/day ANE, 10 additional BBtu/day PennEast (firm transportation) |
| Scenario 5: | 7 BBtu/day ANE, 10 additional BBtu/day PennEast (firm transportation) |
| Scenario 6: | 7 BBtu/day ANE, 10 additional BBtu/day PennEast (interruptible transportation) |
| Scenario 7: | No ANE, 10 additional BBtu/day PennEast (firm transportation), 7 BBtu/day replacement for 1996/97 delivery |
| Scenario 8: | No ANE, 10 additional BBtu/day PennEast (interruptible transportation), 7 BBtu/day replacement for 1996/97 delivery |

<u>Cases:</u>

| | |
|---|---|
| Case 1: | Base Demand Forecast, Low Interruptible Margin, 29 Year Period of Analysis |
| Case 2: | High Demand Forecast, Low Interruptible Margin, 29 Year Period of Analysis |
| Case 3: | Base Demand Forecast, High Interruptible Margin, 29 Year Period of Analysis |
| Case 4: | High Demand Forecast, High Interruptible Margin, 29 Year Period of Analysis |

<u>Sources</u>: Exh. BGC-1, Charts I-D-1 and I-D-2

TABLE 5

Boston Gas Company
PennEast/ANE Decision
Scenarios and Cases Evaluated in Revised Cost Analysis

<u>Scenarios:</u>

| | |
|---|---|
| Base Case: | 17 BBtu/day ANE, no additional PennEast |
| Scenario 1: | No ANE, 10 additional BBtu/day PennEast (firm transportation) |
| Scenario 2: | No ANE, 10 additional BBtu/day PennEast (interruptible transportation) |
| Scenario 3: | 17 BBtu/day ANE, 10 additional BBtu/day PennEast (interruptible transportation) |
| Scenario 6: | 7 BBtu/day ANE, 10 additional BBtu/day PennEast (interruptible transportation) |
| Scenario 8: | No ANE, 10 additional BBtu/day PennEast (interruptible transportation), 7 BBtu/day replacement for 1996/97 delivery |
| Scenario 9: | No ANE, no additional PennEast |

<u>Cases:</u>

| | |
|---|---|
| Case 1: | Low Demand Forecast, Low Interruptible Margin, 30 Year Period of Analysis |
| Case 2: | Base Demand Forecast, Low Interruptible Margin, 30 Year Period of Analysis |
| Case 3: | High Demand Forecast, Low Interruptible Margin, 30 Year Period of Analysis |
| Case 4: | Low Demand Forecast, Mid Interruptible Margin, 30 Year Period of Analysis |
| Case 5: | Base Demand Forecast, Mid Interruptible Margin, 30 Year Period of Analysis |
| Case 6: | High Demand Forecast, Mid Interruptible Margin, 30 Year Period of Analysis |
| Case 7: | Low Demand Forecast, High Interruptible Margin, 30 Year Period of Analysis |
| Case 8: | Base Demand Forecast, High Interruptible Margin, 30 Year Period of Analysis |
| Case 9: | High Demand Forecast, High Interruptible Margin, 30 Year Period of Analysis |
| Case 10: | Base Demand Forecast, Low Interruptible Margin, 15 Year Period of Analysis |
| Case 11: | Base Demand Forecast, High Interruptible Margin, 15 Year Period of Analysis |
| Case 12: | Base Demand Forecast, Low Interruptible Margin, 30 Year Period of Analysis, Base Commodity Cost |
| Case 13: | Base Demand Forecast, Low Interruptible Margin, 30 Year Period of Analysis, High Commodity Cost |
| Case 14: | Base Demand Forecast, Low Interruptible Margin, 30 Year Period of Analysis, Low Commodity Cost |

<u>Sources</u>: Exhs. HO-PL-22, HO-RR-30

Appeal as to matters of law from any final decision, order or ruling of the Siting Council 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 Council be modified or set aside in whole or in part.

Such petition for appeal shall be filed with the Siting Council within twenty days after the date of service of the decision, order or ruling of the Siting Council, or within such further time as the Siting Council 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).

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

| | | |
|---|---|---|
| In the Matter of the Petition of Eastern Energy Corporation for Approval to Construct a Bulk Generating Facility and Ancillary Facilities | ) | EFSC 90-100A |

# FINAL DECISION ON COMPLIANCE WITH ENVIRONMENTAL CONDITIONS

Robert P. Rasmussen
Hearing Officer
July 30, 1992

On the Decision:

Phyllis Brawarsky
William S. Febiger
Michael B. Jacobs

APPEARANCES: John A. DeTore, Esq.
Barry P. Fogel, Esq.
Tim Ferris, Esq.
Keohane, DeTore & Keegan
21 Custom House Street
Boston, Massachusetts 02110
FOR: Eastern Energy Corporation
<u>Petitioner</u>

Frederick D. Augenstern, Esq.
Assistant Attorney General
Office of the Attorney General
Environmental Protection Division
One Ashburton Place, 19th Floor
Boston, Massachusetts 02108
<u>Intervenor</u>

Melanie Hagopian, Esq.
Andy Backman
Department of Environmental Protection
100 Cambridge Street, 14th Floor
Boston, Massachusetts 02202
<u>Intervenor</u>

Scott Alfonse, City Planning Department
Armand Fernandes, Jr., Esq.
Richard Moore, Esq.
The City of New Bedford
Office of City Solicitor
133 William Street
New Bedford, Massachusetts 02740
<u>Intervenor</u>

Irwin Marks, Steven Cook
GNB NO-COALition
1025 Pequot Street
New Bedford, Massachusetts 02740
<u>Intervenor</u>

Robert H. Ladino
81 Long View Road
New Bedford, Massachusetts 02740
<u>Interested Person</u>

Mary and Donald Marshall
213 Heritage Drive
New Bedford, Massachusetts 02740
<u>Interested Person</u>

Henry Riley
408 County Road
New Bedford, Massachusetts 02740
<u>Interested Person</u>

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TABLE 1: Average Additional Costs for Lower Sulfur Coals

# I. INTRODUCTION

## A. Background

On August 2, 1991, the Energy Facilities Siting Council ("Siting Council") conditionally approved the petition of Eastern Energy Corporation ("EEC" or "Company") to construct a 300 megawatt circulating fluidized bed ("CFB") coal-fired cogeneration facility and certain ancillary facilities in the City of New Bedford. Eastern Energy Corporation, 22 DOMSC 188 (1991) ("EEC"). In EEC, the Siting Council found that EEC had established that upon confirmation by the Siting Council of adequate compliance with specific conditions, the Company's proposed project is likely to be viable. Id. at 312-313. Further, the Siting Council found that the Company had failed to establish that sulfur dioxide ("$SO_2$") and carbon dioxide ("$CO_2$") emissions and noise impacts are minimized. Id. at 413-414. Finally, as a result of the findings relating to $SO_2$, $CO_2$, and noise impacts, the Siting Council made no finding as to whether the cost estimates for the proposed facility are minimized consistent with the mitigation of environmental impacts. Id. at 414. Therefore, the Siting Council specified the types of additional evidence on project viability and proposed and alternative environmental mitigation strategies, including resultant impact levels and costs, that EEC would need to provide in order for the Siting Council to make the additional findings that would support a decision allowing EEC to construct its proposed facility. Id.

As a result, the Siting Council approved EEC's petition subject to six conditions and seven orders.[1] Id. at 312-313,

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1/ The Siting Council noted that EEC must comply with all conditions before construction of the proposed facility can commence. EEC, 22 DOMSC at 315 n.235. The Siting Council further noted that EEC must fulfill the orders contained in that decision during the course of construction and operation of the facility. Id.

410-413. The Siting Council expected that EEC would address the conditions by submitting two distinct compliance filings -- one filing to address the viability conditions, and a separate filing to address the environmental conditions. Id. at 416. This review focuses on EEC's submission relative to the environmental conditions.[2]

The environmental conditions required the Company to provide: (1) a comprehensive analysis of the availability, environmental impacts, and economic impacts of the use of coal with a range of sulfur contents lower than 1.8 percent; (2) a comprehensive analysis of the economic and environmental impacts of attaining a range of $CO_2$ offsets; and (3) a revised analysis of the noise impacts of the proposed facility at the closest residence and a description of strategies to further minimize noise impacts of the facility at the northern property line. Id. at 359, 360, 377. The Siting Council found that, if EEC provides this information, and the Siting Council determines, after review, that: (1) the use of 1.8 percent sulfur coal or a lower sulfur coal achieves the appropriate balance based on Siting Council standards, then the proposed facility's $SO_2$ emissions will be adequately minimized; (2) the Company's plan for attaining $CO_2$ emission offsets or a different $CO_2$ emission offset plan achieves the appropriate balance based on Siting Council standards, then the $CO_2$ emissions will be adequately minimized; and (3) the Company's plan for reducing noise impacts or a different plan for reducing noise impacts is consistent with

2/ EEC has not yet submitted its viability compliance filing. The viability conditions required the Company to provide a copy of: (1) an appropriate, executed Engineering, Procurement, and Construction contract; (2) an appropriate, executed Operation and Maintenance contract; and (3) an executed coal supply agreement which includes terms similar to those contained in EEC's Request for Proposals for coal supplies. EEC, 22 DOMSC at 303, 312.

the minimization of noise impacts, then the noise impacts will be adequately minimized. Id. at 369, 411.

The Siting Council also found that upon compliance with all conditions and orders set forth in the decision,[3] the construction of the proposed facility and ancillary facilities will be consistent with providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. Id. at 415.

B. Procedural History

On February 10, 1992, EEC submitted to the Hearing Officer its environmental compliance filing (Exhs. HO-65A,[4] HO-65B, HO-65C, HO-65D, HO-65D, Attachments A, B, & C, HO-65E). All parties were afforded an opportunity to address the matters contained in the environmental compliance filing. See, EEC, 22 DOMSC at 415 n.234; see also, Hearing Officer Memorandum of January 23, 1992. The Siting Council commenced a five-week discovery period on February 11, 1992. The discovery period was followed by five days of evidentiary hearings, commencing April 3, 1992 and ending April 23, 1992. EEC presented seven witnesses: Arshad Nawaz, project engineer for Bechtel Power

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3/ The Siting Council noted that the filing of the required information would be the Company's next step toward a final approval in the case. EEC, 22 DOMSC at 415 n.236. The Siting Council further noted that "[i]f the Company's compliance filings, including appropriate mitigation measures and/or design changes to the facility, fail to establish that environmental impacts will be adequately minimized, the Company's petition to construct will be rejected." Id.

4/ Exhibit HO-65A contains introductory materials and three Technical Appendices. Technical Appendix I ("HO-65A, TA I") is entitled "Sulfur Dioxide Emissions" and contains a separate report -- "Analysis of Lower Sulfur Coal Costs for Eastern Energy Corporation" prepared by EnviroFuels ("HO-65A, EnviroFuels Report"). Technical Appendix II ("HO-65A, TA II") is entitled "Carbon Dioxide Mitigation". Technical Appendix III ("HO-65A, TA III") is entitled "Project Revisions".

Corporation, who testified regarding project design and technical aspects of the project; James H. Slack, senior program manager for ENSR Consulting and Engineering ("ENSR"), who testified regarding air permits and air emissions; Ben G. Henneke, Jr., president of EnviroFuels Corporation ("EnviroFuels"), who testified regarding sulfur content, availability, and costs of different coals; Robert M. Earsy, a noise consultant, who testified regarding noise impacts of the facility; Glen Harkness, vice president of ENSR, who also testified regarding noise impacts of the facility; James L. Croyle, general manager for the project, who testified regarding $CO_2$ mitigation, $SO_2$ offsets, project viability, and project costs; and James A. Booth, principal engineer of the Boston consulting office of R.W. Beck, who testified regarding dispatch of the proposed facility.

Briefs were filed on May 21, 1992 by the Greater New Bedford NO-COALition ("NO-COAL Brief") and the Attorney General ("Attorney General Brief"), both intervenors in the proceeding, and by EEC ("EEC Brief").

The Hearing Officer entered 115 exhibits into the record, consisting of the environmental compliance filing and responses to information and record requests. The Attorney General and EEC entered 59 exhibits into the record. NO-COAL entered 27 exhibits into the record.[5]

C. Facility Changes

In the development of its environmental compliance filing, EEC reviewed certain design features of the project and proposed several changes to the project design (Exh. HO-65A, TA III). The first of these changes is a change from three non-reheat boilers

5/ The review of the environmental compliance filing is, in essence, a continuation of the review of EEC's original petition to construct a bulk generating facility (EFSC 90-100). As such, the exhibits that were moved into evidence in that proceeding are a part of the record in this review of the Company's environmental compliance filing.

to two reheat boilers (id., pp. 1-3, Exh. HO-65A, p. 7). The second change is a reconfiguration of the site which rotated the boiler buildings and baghouses 90 degrees counter-clockwise and relocated the fuel storage building. (Exhs. HO-65A, TA III, p. 2, HO-65E).[6] These changes are discussed below.

1. Boilers

The Company indicated that it decided to utilize two reheat boilers rather that three non-reheat boilers to increase the overall project efficiency (id., p. 1). The Company's witness, Mr. Nawaz, explained that this is accomplished "by extracting a portion of the steam after it passes through the

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6/ In EEC, the Siting Council required EEC to "utilize ammonia or urea injection [selective non-catalytic reduction ("SNCR")] to reduce Nitrogen Oxide ("NOx") emissions after three years of facility operation, if combustion optimization did not achieve expected reductions of NOx emissions from 0.30 pounds per million british thermal units ("lb/MMBtu") to 0.18 lb/MMBtu or lower" (22 DOMSC at 357). In its environmental compliance filing, EEC committed to install SNCR during construction of the proposed facility and to utilize it as soon as the facility goes into service (Exh. HO-65A, p. 6). EEC indicated that NOx emissions would be reduced from 0.30 lb/MMBtu to 0.15 lb/MMBtu through use of this technology, and that a boiler vendor would guarantee the 0.15 lb/MMBtu NOx emission rate using SNCR (Exh. AG-152; Tr. 16, p. 100).

The Company indicated that associated with the reduction in NOx emissions through the use of SNCR is the emission of unreacted ammonia to the atmosphere ("ammonia slip") (Exh. AG-152; Tr. 16, pp. 102-105). EEC indicated that the SNCR vendor will guarantee that the ammonia slip from the proposed facility will not exceed 10 parts per million (Tr. 16, p. 103). EEC stated that, based on such an emission rate, the results of the Company's dispersion modeling analysis illustrate that the predicted 24-hour and annual concentration maximums are well below the air-guideline concentrations of the Massachusetts air toxics policy overseen by the Department of Environmental Protection ("DEP") (id.).

The Siting Council notes that EEC will also be required to obtain a permit for the storage of aqueous ammonia on-site prior to the construction of the facility (see, Exh. NC-15). Additionally, a spill prevention plan will be required of EEC prior to the facility's operation (id.).

high-pressure stage of the turbine, redirecting it back to the boiler to be further heated. And then it goes into an intermediate-pressure or the low-pressure portion of the turbine. The intent of that is to get more power out of it for the same amount of steam" (Tr. 16, p. 7). Mr. Nawaz, further indicated that the reheat boiler, being more efficient, would burn less coal and use less limestone to produce the same amount of steam (id., pp. 8, 111).

The record indicates that the revised design utilizing two reheat boilers will improve plant efficiency by approximately three percent and, therefore, will reduce air emissions, solid wastes, and transportation impacts by approximately three percent as a result (id., pp. 7-8; Exhs. HO-65A, TA III, pp. 1-3, HO-65A, p. 7). Thus, this proposed project change will reduce environmental impacts. The record further indicates that capital cost estimates are expected to decline and operating expenses should significantly decrease (Exh. HO-65A, TA III, p. 1). As there is no net increase in costs or environmental impacts expected from this revised design, no change to the conditional approval is necessary. The Siting Council notes that cost-effective improvements to proposed facilities which increase efficiency and, therefore, have the ability to further lessen environmental impacts, should continually be considered by developers of such facilities.

2. Site Reconfiguration

In its efforts to address concerns relative to noise impacts of the proposed facility that were raised in EEC and in order to avoid an Army Corps of Engineers ("ACE") jurisdictional wetland, EEC reconfigured a portion of its site (id., pp. 1-2, Exh. HO-65E) (see Section II.B.1, below, for a discussion of EEC's noise mitigation proposal). This reconfiguration included a counter-clockwise rotation of the boiler buildings and baghouses which would allow the Company to locate the air-cooled condenser to the south of the power block providing additional distance to the northern noise receptors and a barrier wall shielding effect on the noise generated by the condenser in a northerly direction (id., Exh. HO-65B, p. 2-1). The reconfiguration also would relocate the fuel storage building, oil storage tank and limestone storage building farther to the east on the site, relocate the site access road to the west of the power block and air-cooled condenser, locate an area for the on-site storage of aqueous ammonia to the north of the boiler buildings and move the railyard to the west of its original position (Exhs. HO-65A, TA III, p. 2, HO-65E).

During the development of the record in the initial proceeding in this case, it was determined that approximately 0.9 acres of wetlands of the type regulated under the Massachusetts Wetland Protection Act (G.L. c. 131, §§40, 40A; 310 CMR 10.01 et seq.) would be filled during construction of the proposed facility (Exh. HO-E-60; Tr. 2, pp. 110-115). EEC's reconfigured site plan indicates that by moving the rail yard to the west of its original location and realigning the facility access road to avoid alteration of on-site wetlands, the Company would avoid altogether any alteration to wetlands that these project features previously were expected to cause (Exhs. HO-65E, NC-25). The site reconfiguration would also lessen impacts on wetlands by placing the railroad on a trestle bridge to span the wetland to the north of the facility site (id.). The net result of the site reconfiguration would be to reduce impacts to on-site wetlands from 35,930 square feet, as indicated on the original plan, to 10,771 square feet, as indicated on the reconfigured plan (Exh. NC-25).

In addition, in the original proceeding, an approximately 1.2 acre area that would likely fall under the jurisdiction of the ACE pursuant to the federal definition of wetland, was identified by the Company, which, to some extent, would also have required filling (Tr. 2, pp. 110-115). The alteration of this area would have required a federal permit from the ACE (Tr. 2, p. 110-115). In the Company's environmental compliance filing, the reconfiguration of the site would completely avoid this area as a result of the relocation of the air-cooled condenser mentioned above (Exhs. HO-65A, TA III p. 2, HO-65E; compare with Exh. HO-E-83).

The Siting Council recognizes the improvements resulting from the proposed site reconfiguration with respect to impact on wetlands. Nevertheless, the Siting Council notes that the Company is still bound by the order in EEC to replicate wetlands on-site in an amount greater than the amount of wetlands that will be altered (22 DOMSC at 382, 412).

EEC also stated that the reconfiguration of the site would result in the movement of the coal storage enclosure to the east of its original location thereby allowing the siting of the air-cooled condenser at the northern end of this area (Exh. HO-65E). This change necessitates an amendment to the order in EEC relative to the maintenance of a 30-foot vegetated area between the on-site wetlands and the coal storage enclosure.[7] As the air-cooled condenser has, in essence, moved into a part of the location that was affected by this order, the Siting Council expects EEC to maintain at least 30 feet of existing vegetation, during construction and operation, between the on-site wetlands and the air-cooled condenser, and between the on-site wetlands and (1) that corner of the coal storage enclosure that will remain relatively unmoved, and (2) the rail spur extending to the south of the coal storage enclosure.

In EEC, the Siting Council also ordered the Company to maintain at least ten feet of existing vegetation, during

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7/ In EEC, the Company was ordered to maintain at least 30 feet of existing vegetation, during construction and operation of the proposed facility, between the on-site wetlands and (1) the coal storage enclosure, and (2) the rail spur extending to the south of the coal storage enclosure (22 DOMSC at 392).

construction and operation of the proposed facility on the western boundary of the proposed site, in the vicinity of the parking area, oil storage tank and limestone storage building, where the tree clearing line is proposed to extend along the Acushnet Cedar Swamp State Reservation boundary (22 DOMSC at 403). In its environmental compliance filing, the Company indicated that the site reconfiguration would move the site access roadway on the western side of the project closer to the western property boundary than in the original proposal (Exhs. HO-65E, HO-E-83). The Company further indicated that the relocation of the oil storage tank and limestone storage building will move them further to the east, away from this boundary (id.). As the impacts that would result from a roadway are different from those associated with a storage tank or building, the Siting Council expects EEC to locate the site access roadway as far to the east as is practicable, and maintain existing vegetation between the site access roadway and the Acushnet Cedar Swamp State Reservation boundary, but in no case should the buffer in this area be less than the already required ten feet.

Finally, the Siting Council fully expects the Company to maintain at least 100 feet of existing vegetation, during construction and operation of the proposed facility along all other portions of the western boundary and along the southern boundary of the proposed site (id.).[8]

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8/ In EEC, the Siting Council ordered the Company to maintain buffers of existing vegetation based on the proposed site configuration at that time. As the site access roadway was located further east in the original site plan than in the site re-configuration, no specific guidance was given with reference to maintaining a buffer of existing vegetation between the boundary and the roadway. Necessary encroachment into the 100 feet of existing vegetation that is to be maintained along the western and southern site boundaries to construct and maintain the roadway should be minimized. However, the Siting Council expects that a minimum 30-foot buffer between the roadway and on-site wetlands will be maintained.

## II. ANALYSIS OF THE PROPOSED FACILITIES

### A. Standard of Review

G.L. c. 164, §69I, requires a facility proponent to provide information regarding "other site locations." In implementing this statutory mandate, the Siting Council requires the 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.

In order to determine whether the facility proponent has shown that its proposed facilities' siting plans are superior to alternatives, the Siting Council has required a facility proponent to demonstrate that it has examined a reasonable range of practical facility siting alternatives. In order to determine whether the facility proponent has shown that its proposed facilities are sited at locations that minimize costs and environmental impacts while ensuring supply reliability, the facility proponent must demonstrate that it has achieved an appropriate balance (1) among various environmental impacts, and (2) among environmental impacts, costs and reliability. EEC, 22 DOMSC at 337. A facility which achieves this balance is a facility that fulfills the statutory mandate of providing energy with the minimum impact on the environment at the lowest possible cost. G.L. c. 164, §69H.

In EEC, the Siting Council found that the Company had considered a reasonable range of practical siting alternatives (22 DOMSC at 326). The Siting Council determined that EEC had not established that it minimized environmental impacts with respect to noise and $SO_2$ and $CO_2$ emissions. Id. at 359, 360, 377. The Siting Council also determined that the Company had provided only limited information on the costs of alternative control strategies for minimization of air quality impacts related to $SO_2$ and $CO_2$ emissions, and for the minimization of noise impacts. Id. at 330. The Siting Council further determined that its review of this information is necessary to ensure consistency with the standard that energy facilities necessary to ensure a reliable energy supply for the Commonwealth be built at the least cost with a minimum impact on the environment. Id. at 330-331. As a result, the Siting Council conditioned approval of the proposed facility on (1) the Company's providing additional information on these issues, and (2) a Siting Council finding that the appropriate balance among cost, environmental impact and reliability had been achieved. Id. at 331, 337.

With respect to noise, the Siting Council found that the Company failed to establish that noise levels had been adequately minimized. Id. at 377. The Siting Council stated: "[s]hould the Company provide (1) a revised analysis of the noise impacts of the proposed facility at the closest residence, and (2) a description of the various strategies the Company would use to further minimize noise impacts of the facility at the northern property line," the Siting Council would determine whether the Company had established that the noise levels of the proposed facility "have been adequately minimized or whether noise levels must be further minimized in order to meet the Siting Council's standard." Id.

With respect to $SO_2$ emissions, the Siting Council found that the Company had failed to establish that $SO_2$ emissions had been adequately minimized. Id. at 359. The Siting Council stated: "[s]hould the Company provide a comprehensive analysis of the availability, environmental impacts, and economic impacts of the use of coal with a range of sulfur contents lower than 1.8 percent," the Siting Council would determine whether the Company had established that the $SO_2$ emissions "have been adequately minimized, or whether $SO_2$ emissions must be further minimized in order to meet the Siting Council's standard." Id.

With respect to $CO_2$ emissions, the Siting Council found that the Company had failed to establish that $CO_2$ emissions had been adequately minimized. Id. at 360. The Siting Council stated: "[s]hould the Company provide a comprehensive analysis of the environmental and economic impacts of attaining a range of $CO_2$ emission offsets," the Siting Council would determine whether the Company had established that the facility's $CO_2$ emissions "have been adequately minimized or whether $CO_2$ emissions should be further minimized in order to meet the Siting Council's standard." Id.

Finally, with respect to costs, the Siting Council could make no finding as to whether EEC had established that the cost estimates of the proposed facility were minimized consistent with the mitigation of environmental impacts. Id. at 331. The Siting Council stated: "[s]hould the Company submit the information regarding control technologies for $SO_2$, $CO_2$, and noise, specified in the conditions" as set forth above, the Siting Council would be able "to determine whether the cost estimates associated with the proposed facilities are minimized consistent with the mitigation of environmental impacts." Id.

In the following sections, the Siting Council analyzes whether the Company has complied with the environmental conditions, and whether the Company has adequately minimized environmental impacts. The Siting Council also analyzes whether the cost estimates of the proposed facilities are minimized consistent with the minimization of environmental impacts.

## B. Environmental Analysis of the Proposed Facilities

### 1. Noise

#### a. Description

In EEC, the Siting Council found that the Company had failed to establish that noise levels had been adequately minimized (22 DOMSC at 377). The Siting Council had serious concerns regarding the Company's (1) estimate of background noise, and (2) analysis of the noise impacts from the proposed facility. Id. at 375. The Siting Council indicated that specific areas of concern with the Company's noise analysis were: (1) the lack of a comprehensive set of seasonal, weekend, and weekday measurements of background noise; (2) the failure of the Company to document its assumptions; (3) the use of a proxy location for noise measurements without justifying the comparability of locations; (4) the failure to analyze the impacts of all potential noise sources; and (5) the magnitude of the noise increase at the northern property line. Id. at 375-377. The Siting Council found that if EEC provided (1) a revised analysis of the noise impacts of the proposed facility at the closest residence, and (2) a description of the various strategies the Company would use to further minimize noise impacts of the facility at the northern property line, the Siting Council would determine whether the Company had established that the noise levels of the proposed facility have been adequately minimized or whether noise levels must be further minimized in order to meet the Siting Council's standard.[9] Id. at 377.

In response to this condition, EEC submitted a new analysis of ambient background noise levels at the closest residence, and revised estimates of noise increases at the closest residence and the northern property line resulting from the operation of the proposed facility (Exh. HO-65B, pp. 3-9 to 3-23, 5-2 to 5-6; Tr. 17, pp. 4-8). The Company indicated that its revised noise analysis more accurately reflects measured ambient noise levels at the residence closest to the facility and

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9/ The Siting Council noted that this condition did not preclude the Company from proposing additional noise mitigation measures when it files its analyses with the Siting Council. EEC, 22 DOMSC at 377 n.194. The Siting Council further noted that, if EEC's analyses indicated that greater noise mitigation would achieve an appropriate balance between minimizing noise impacts and minimizing costs, it would be incumbent upon EEC to modify its proposal accordingly. Id.

incorporates changes in the principal sources of noise resulting from operation of the proposed facility (id.).

In the initial stages of its revised analysis, EEC undertook an additional survey of ambient noise levels during both daytime and nighttime periods at the closest residence to the facility and at the property lines (Exh. HO-65B, pp. 1-1, 3-9, 3-10).[10] In response to the Siting Council's concerns relative to the use of a proxy location for noise measurements at the nearest residence, the Company stated that field measurements of the existing baseline noise recorded in the revised noise analysis were taken at the actual location of the nearest residential structure, which is at the south end of DeMoranville Lane, approximately 4,500 feet northwest of the center of the proposed facility (id., pp. 3-1, 3-5). The Company also stated that it used the lowest measured baseline noise data for the analysis of facility noise impacts at the nearest residence (Exh. HO-E-161). In addition, EEC developed new estimates of the noise increase at the facility property lines and the nearest residence, and provided maps of the isopleth of the 10 decibel increase (Exhs. HO-65B, pp. 4-10 to 4-14, HO-RR-67).

As part of its revised analysis, EEC also estimated the additional mitigation that would be achieved by various strategies to limit the noise increase at the northern property line and the closest residence, and the costs of each mitigation

10/ EEC stated that it made nine measurements of existing baseline noise at the nearest residence on one weekday in August, 1991 and three weekdays in December, 1991 and January, 1992 reflecting both daytime and nighttime conditions (Exh. HO-65B, p. 3-12). EEC also stated that it made five measurements of existing baseline noise at the nearest residence on two weekend days and one weekend night in August, 1991, and 14 measurements on three weekend days and four weekend nights in December, 1991 (id., p. 3-22). In addition, EEC made six measurements of existing baseline noise at the proposed facility's northern property line and additional measurements at the eastern property line and at several other receptors beyond the property boundaries (id., pp. 3-12, 3-13, 3-22).

strategy (Exh. HO-65B, pp. 3-9 to 3-23, 5-2 to 5-6; Tr. 17, pp. 4-8). EEC stated that daytime noise increases would be 15 decibels at the northern property line and 8 decibels at the nearest residence before providing any additional mitigation measures (Exh. HO-65B, p. 5-4). The additional noise mitigation proposed by the Company, however, would reduce the increases to 10 decibels or less at the northern property line and 6 decibels at the nearest residence (id.).

In addition to the noise mitigation benefits of the site reconfiguration discussed in Section I.C.2, above, EEC indicated that it identified the following additional noise mitigation strategies: (1) a coal car unloader package; (2) a quiet (three decibel reduction) yard locomotive package; (3) a quieter (six decibel reduction) yard locomotive package; (4) an indexer system;[11] and (5) a super low noise air-cooled condenser with 14 percent greater surface area than the low noise air-cooled condenser[12] (id., pp. 5-1 to 5-6). The Company further indicated that it evaluated the effectiveness of these alternative noise mitigation strategies, individually and in combination with each other[13] (id., pp. 2-4, 5-1 to 5-5). Based on its analysis, the Company stated that it proposes to reduce the noise levels produced by the facility at the northern property line and the closest residence by: (1) reconfiguring the

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11/ The Company's witness, Mr. Harkness, explained that an indexer system is a winch operation that winches the railroad cars through the unloading facility, thereby eliminating the need for a yard locomotive to move the cars through that facility (Tr. 17, p. 80). The Company noted that the indexer system would provide the same benefits as the quieter yard locomotive package but would have significantly greater cost impacts (Exh. HO-65B, pp. 5-3, 5-4).

12/ The facility as proposed would use the low noise air-cooled condenser (Exh. HO-65B, p. 5-1).

13/ The Company's analyses of these mitigation strategies all assumed noise levels that would result after the reconfiguration of the site (Exh. HO-65B, p. 5-1).

site layout which would separate and shield the condenser and the yard locomotive from the northern property line and the closest residence; (2) implementing the quieter yard locomotive package which would modify the yard locomotive with silencers, more effective mufflers, and acoustical panels; and (3) implementing the coal car unloader package which would modify the coal car unloading shed to seal and insulate this structure (id., pp. 2-1, 5-1, 5-2, 5-3 to 5-6). The Company indicated that its proposed plan would reduce noise levels at the northern property line to 10 decibels or less at all times, and at the nearest residence to 6 decibels or less at all times (id., p. 5-4; Tr. 17, pp. 4-6). EEC estimated the cost of this proposed plan to be $230,000 (Exh. HO-65B, pp. 2-1, 5-1, 5-2, 5-3 to 5-6).

The Company stated that using the combination of noise mitigation strategies that comprise the Company's proposed plan but substituting a super low noise condenser for the low noise condenser, would reduce noise at the northern property line at night to five decibels (id., p. 5-4; Tr. 17, pp. 4-8). Daytime noise levels at that location would be the same with either condenser (id.). The Company further indicated that the substitution of the super low noise condenser for the low noise condenser would also reduce the increase in noise levels at the nearest residence during the daytime from six decibels to five decibels (id.). Use of either option, however, would have an identical impact on nighttime noise levels at that location -- an increase in two decibels (id.).

EEC stated that the combination of noise mitigation strategies which includes the super low noise condenser would cost $11,830,000 -- $11,600,000 more than the Company's proposed plan (id., pp. 5-4, 5-5). EEC further noted that due to the larger size of the super low noise condenser, its inclusion would necessitate additional site modifications that would result in additional impacts to on-site wetlands or wetland buffers (Exhs. HO-E-157, HO-65E; Tr. 16, pp. 84-93). Based on the additional cost and potential wetland impacts compared to the additional noise reduction of one decibel or less at the nearest residence, EEC concluded that installation of the super low noise condenser was not warranted (Exh. HO-65B, p. 5-5).

Finally, EEC indicated that its revised analysis continues to show noise increases at the western and southern property lines exceeding the DEP 10 decibel guideline, both with and without additional noise mitigation (Tr. 17, pp. 24-25). However, the Company indicated its isopleth analysis shows that noise increases exceeding 10 decibels would be limited to industrially zoned land to the northwest of the facility and areas within the Acushnet Cedar Swamp (Exh. HO-RR-67).[14]

b. Analysis

In past decisions, the Siting Council has reviewed estimated noise impacts of proposed facilities for general consistency with applicable state and local requirements, including the DEP's guideline relative to an increase in noise levels in excess of 10 decibels above background noise at the nearest residence. Enron Power Enterprise Corporation, 23 DOMSC 1, 210 (1991) ("Enron"); West Lynn Cogeneration, 22 DOMSC 1, 100 (1991); MASSPOWER, 20 DOMSC 301, 389 (1990); Altresco-Pittsfield, Inc., 17 DOMSC 351, 401 (1988) ("Altresco-Pittsfield"). In addition, the Siting Council has considered the significance of expected noise increases which, although below 10 decibels, may adversely affect existing residences or other sensitive receptors

14/ EEC stated that its planned site reconfiguration would relocate yard locomotive noise to the south in order to help reduce noise impacts at the nearest residence and northern property line (Tr. 17, pp. 5-6). However, in conjunction with other proposed noise mitigation, the estimated noise increase at the western property line would remain unchanged at 27 decibels (id., pp. 24-25). EEC asserted that it has no reason to expect any adverse impact on wildlife in the Acushnet Cedar Swamp, located to the west of the proposed site, from the anticipated noise impacts (id.).

such as schools. Enron, 23 DOMSC at 210; Altresco-Pittsfield, 17 DOMSC at 48.

Here, EEC has provided an updated analysis of expected noise impacts using actual measurements of background noise at the nearest residence. EEC used an appropriate methodology to estimate increases in noise levels from operation of the proposed facility at the nearest residence as well as at other locations. Moreover, EEC conducted an appropriate analysis to identify and evaluate a range of noise control strategies. Accordingly, the Siting Council finds that EEC has complied with the condition to provide (1) a revised analysis of the noise impacts of the proposed facility at the closest residence, and (2) a description of the various strategies the Company would use to further minimize noise impacts of the facility at the northern property line.

EEC has identified and committed itself to various additional mitigation measures which would reduce the expected noise increases at the northern property line and the nearest residence. In this case, the record demonstrates that operation of the proposed facility, as modified, would increase noise levels at the nearest residence by 6 decibels during the day and 2 decibels during the night -- levels both below the DEP guideline and not exceeding levels accepted in previous Siting Council reviews. Further, the Company's decision to use the low noise condenser rather than the super low noise condenser is appropriate. The significant additional costs of the super low noise condenser and the increased likelihood of impacts to on-site wetlands or wetland buffers from this condenser are not justified given the marginal reduction in noise level increases that such a condenser would produce. It is this type of balancing that is necessary for the Siting Council to determine whether a proposed facility will provide a necessary energy supply at the lowest cost with the least impact on the environment.

Accordingly, based on the foregoing, the Siting Council finds that EEC has established that the noise levels of the proposed facility with the revised mitigation strategy described above have been adequately minimized consistent with the minimization of cost.

### c. Conclusions on Noise

The Siting Council has found that EEC has complied with the condition to provide (1) a revised analysis of the noise impacts of the proposed facility at the closest residence, and (2) a description of the various strategies the Company would use to further minimize noise impacts of the facility at the northern property line. The Siting Council has also found that EEC has established that the noise levels of the proposed facility with the revised mitigation strategy described above have been adequately minimized consistent with the minimization of cost. Accordingly, the Siting Council finds that the operation of the proposed facility would have an acceptable impact on community noise levels.

## 2. Air Quality

### a. $SO_2$ Emissions

In EEC, the Siting Council found that the Company had failed to establish that $SO_2$ emissions had been adequately minimized (22 DOMSC at 359). The Siting Council determined that the Company had not provided adequate information regarding its decision to use 1.8 percent sulfur coal and had not fully explored the use of lower sulfur coal. Id. at 358. However, the Siting Council recognized that a comprehensive analysis of the availability, environmental impact and economic impact of lower sulfur coals may have allowed the Company to demonstrate that the $SO_2$ emissions from the proposed facility were adequately minimized with the use of 1.8 percent sulfur coal.[15] Id. at 359. Therefore, the Siting Council required EEC to provide a comprehensive analysis of the availability, environmental impacts, and economic impacts of the use of coal with a range of sulfur content below 1.8 percent. Id.

The Siting Council indicated that the analysis should include information regarding location of mines and reserves, mine prices, transportation availability and costs, resulting emission rates, consideration of mixing 1.8 percent sulfur coal with lower sulfur coal, and the impact of the cost of different coals on the financeability of the project and the ability of the Company to market power from the project. Id. The Siting Council found that if (a) the Company provided a comprehensive analysis of the availability, environmental impact and economic impact of lower sulfur coal, and (b) the Siting Council determines, after review, that the use of 1.8 percent sulfur coal or a lower sulfur coal is consistent with the minimization of $SO_2$ emissions, then the proposed facility's $SO_2$ emissions would be adequately minimized. Id. at 361-362.

In response, EEC provided an analysis of the availability, environmental impacts and economic impacts of the use of lower sulfur coals in its proposed facility (Exh. HO-65A, TA I). Based on its analysis, the Company asserted that use of lower sulfur coal would not be a cost-effective means to reduce $SO_2$ emissions at the proposed facility (id., p. 5).

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15/ Under the Company's original proposal to utilize three non-reheat boilers and 1.8 percent sulfur coal, the Company estimated that the annual $SO_2$ emissions would be 3,474 tons per year ("tpy"), based on an emission rate of 0.25 lb/MMBtu and 92 percent plant availability (Exh. HO-2A, Table 5.4-2). With the change in facility design to two reheat boilers and the associated decrease in fuel requirements, the Company indicated that with the use of 1.8 percent sulfur coal and an $SO_2$ emission rate of 0.25 lb/MMBtu, the annual $SO_2$ emissions, based on 92 percent plant availability, would decrease to 3,367 tpy (Exh. HO-E-128, Table E-128A).

Although EEC asserted that (1) the $SO_2$ emissions from the proposed facility had been minimized, and (2) the proper balance between cost and environmental impact had been achieved by use of 1.8 percent sulfur coal and an $SO_2$ emission rate of 0.25 lb/MMBtu, EEC proposed to reduce $SO_2$ emissions by means other than the use of lower sulfur coal (Exhs. HO-65A, pp. 5-6, HO-E-135; Tr. 19, pp. 41-42, 62-63). The Company proposed to either (1) further reduce $SO_2$ emissions from the proposed facility by ten percent through facility design and operation, or (2) arrange to reduce $SO_2$ emissions from other electric generating facilities in Massachusetts by 300 tpy (Exh. HO-E-135; Tr. 17, pp. 107-111, Tr. 19, pp. 34-40).[16]

In this section, the Siting Council first reviews the Company's analysis of the use of lower sulfur coal to determine (1) whether the Company has provided a comprehensive analysis of the availability, environmental impact and economic impact of the use of coal with a range of sulfur contents below 1.8 percent, and (2) whether the use of 1.8 percent sulfur coal or a lower sulfur coal is consistent with the minimization of $SO_2$ emissions. The Siting Council then reviews the Company's two alternative approaches to the minimization of $SO_2$ emissions through (1) a reduction of facility $SO_2$ emissions through facility operation while using 1.8 percent sulfur coal, and (2) a reduction in $SO_2$ emissions from other electric generating facilities in Massachusetts, in order to determine whether either approach is consistent with the minimization of $SO_2$ emissions.

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16/ The Company noted that 300 tpy is approximately ten percent of the facility $SO_2$ emissions estimated on the basis of the change in facility design to two reheat boilers (Exh. HO-E-128, Table 128A, Tr. 19, pp. 38-40)

i. Use of Lower Sulfur Coal

(A) Description

In order to prepare its analysis of the availability, environmental impact and economic impact of the use of lower sulfur coal, the Company stated that it solicited bids from 90 percent of the major coal companies active in Pennsylvania, West Virginia, eastern Kentucky, Virginia and Maryland to supply the proposed facility with coal with a sulfur content of 1.8 percent or less (Exh. HO-65A, TA I).[17, 18] For each of the 54 coals provided in the response to the Company's solicitation ("study coals"), the coal supplier specified: (1) the mine price; (2) the sulfur content; (3) the ash content; and (4) the heat content expressed in Btus per pound of coal (Exhs. HO-65A, EnviroFuels Report, HO-E-143; Tr. 18, p. 146).[19]

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17/ The Company indicated that its analysis of the cost of using lower sulfur coals was prepared by EnviroFuels (Exh. HO-65A, TA 1, p. 3).

18/ EnviroFuels indicated that the group of potential coal suppliers included all suppliers who (1) could provide rail delivered coal to the proposed facility at a competitive price via the Conrail, CSX and N&W railroads, and (2) were able to produce at least ten percent, approximately 100,000 tons, of the coal requirements of the proposed facility (Exh. HO-65A, EnviroFuels Report, summary; Tr. 18, pp. 10, 12). Although EnviroFuels did not solicit information regarding coals from other regions of the country in its original solicitation of bids, EnviroFuels did provide a summary of coal characteristics, mine prices and transportation costs for five lower sulfur coals from Wyoming, Colorado, Oklahoma and Alabama (Exhs. HO-65A, TA I, p. 4, AG-157). EnviroFuels indicated that each of these coals would be more costly to the proposed facility than the majority of the eastern coals (Exhs. HO-E-143, AG-157; Tr. 18, pp. 38-39).

19/ The Company's witness, Mr. Henneke, noted that the heat content of coal determines the annual tonnage of the coal that would be required for the operation of the proposed facility (Tr. 18, pp. 33-34, 149). He noted that as the heat content of coal increases, less coal needs to be burned to generate a given quantity of electric power (id.).

The sulfur content of the study coals ranged from 0.7 percent to 2.2 percent (Exh. HO-RR-94).[20]

Based on the sulfur and heat content of each of the study coals and assuming removal of 92 percent of potential $SO_2$ emissions by the CFB technology, the Company calculated the annual $SO_2$ emissions for each of the study coals (Exh. HO-E-143; Tr. 18, pp. 31-32). For each study coal, the Company then determined costs (1) based on the mine price and transportation costs ("delivered cost"),[21] and (2) based on the delivered cost plus the cost of limestone and ash removal ("total cost") (Exh. HO-65A, EnviroFuels Report, p. 6).[22] In addition, the Company determined a mix of study coals, with a maximum sulfur

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20/ Coal suppliers were requested to quote a coal to meet (1) a 1.8 percent sulfur specification, and (2) their most cost-effective lower sulfur coal (Exh. HO-65A, EnviroFuels Report, summary). The Company received two responses for coals with sulfur content above 1.8 percent (Exh. HO-RR-94).

21/ In calculating the delivered cost of each study coal, EEC determined (1) the amount of coal that would be required based on the heat content of each coal, and (2) transportation rates based on rates provided by each of the three railroad companies (Exhs. HO-E-137, HO-65A, EnviroFuels Report, pp. 5-6; Tr. 18, pp. 32-34). The Company noted that in determining coal requirements, it did not take into account the three percent reduction in coal requirements that would result from the use of two reheat boilers (see Section I.C.1, above) (Tr. 18, pp. 33-34).

22/ Mr. Henneke indicated that limestone cost was estimated to be $24 per ton (Exh. HO-65A, EnviroFuels Report, p. 6). Mr. Henneke also indicated that the amount of limestone that would be required for each of the study coals was based on the sulfur content of the coal and the amount of limestone that would provide either (1) a 92 percent reduction in potential $SO_2$ emissions, or (2) maximum $SO_2$ emissions of 2,822 tpy, an amount equal to the $SO_2$ emissions from 1.8 percent sulfur coal and a 92 percent reduction in potential $SO_2$ emissions (id.; Tr. 18, p. 150). In addition, Mr. Henneke indicated that ash disposal costs were based on (1) the amount of ash generated due to coal ash content and limestone requirements, and (2) freight and handling charges to return the ash to the originating mine (Tr. 18, pp. 28-29).

content of 1.8 percent, that had the lowest total cost ("base-case coal") (Tr. 18, p. 24).[23]

The Company then categorized the study coals into five coal regions reflecting geographical location and source railroad, and indicated that the base-case coal was from the Pennsylvania/Conrail region (Exh. HO-65A, EnviroFuels Report, pp. 6, 11).[24] For each coal region, the Company calculated (1) the mean incremental total cost of study coals with respect to the base-case coal, and (2) the mean cost per ton of $SO_2$ emissions avoided from using study coals in lieu of a 1.8 percent sulfur coal (see Table I) (id., p. 15, Exh. AG-162).[25, 26] Based on the mean incremental total cost of study coals, EEC indicated that the least expensive lower sulfur coal would add

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23/ The Company indicated that the base-case coal was actually a mix of three different study coals whose composite sulfur content was 1.6 percent (Exh. HO-RR-95). Mr. Henneke explained that the coal requirements of the proposed facility are approximately one million tpy and that the base-case coal is comprised of a combination of the three lowest total cost study coals that have sulfur content of 1.8, 1.6 and 1.5 percent and annual production capabilities of 25, 25 and 50 percent of facility requirements, respectively (id.).

24/ The Company identified the five coal regions and associated railways as follows: (1) Pennsylvania/Conrail; (2) West Virginia/Conrail; (3) West Virginia and Maryland/CSX; (3) Eastern Kentucky/CSX; and (4) Kentucky, West Virginia and Virginia/N&W (Exh. HO-65A, EnviroFuels Report, p. 7).

25/ Mr. Henneke indicated that EnviroFuels presented the results of its study as averages for coal regions rather than by individual study coals because the information for individual study coals was preliminary, prices were not negotiated, and individual prices could change (Exh. HO-65A, EnviroFuels Report, p. 6). Mr. Henneke stated that, although the cost and availability of any of the individual sources would be subject to change, the overall conclusions of the study would be valid (id.).

26/ In calculating the cost to remove a ton of $SO_2$ emissions, the Company based its calculations on an emission rate of a 1.8 percent sulfur coal and actual cost of the base-case coal (Tr. 18, p. 164).

\$5.3 million to annual operating expenses (Exh. HO-65A, EnviroFuels Report, p. 15). Based on the mean cost per ton of $SO_2$ emissions avoided, the Company indicated that it would cost at least \$6,000 to reduce a ton of $SO_2$ emissions (id., p. 11).

In addition to providing the results of its study expressed as averages for each region, EEC provided detailed information regarding the base-case coal and each of the study coals (Exhs. HO-RR-95, HO-66, HO-E-143). With regard to the base-case coal, the Company calculated that the emission rate would be (1) 0.213 lb/MMBtu, assuming removal of 91.25 percent of potential $SO_2$ emissions, and (2) 0.20 lb/MMBtu, assuming removal of 92 percent of potential $SO_2$ emissions (Exhs. HO-RR-78, HO-RR-95).[27] Mr. Henneke indicated that it would be feasible to use the three coals that comprise the base-case coal at the proposed facility (Tr. 18, p. 156). Mr. Henneke also indicated that the Company would be willing to negotiate with these coal suppliers (id., p. 26).

With regard to the study coals, the Company provided the characteristics of each coal including its total annual cost and the cost to remove a ton of $SO_2$ emissions, relative to a 1.8 percent sulfur coal (Exhs. HO-66, HO-E-143). The Company indicated that there were a number of study coals that had a cost to remove a ton of $SO_2$ emissions, relative to the emissions of a 1.8 percent sulfur coal, in the range of \$3,000 to \$5,000 per ton over the base-case coal (Exh. HO-66; Tr. 18, p. 164).

In addition to considering the mixing of 1.8 percent sulfur coal with lower sulfur coals to form the base-case coal, EEC further discussed the mixing of coals of varying sulfur content (Exh. HO-140, rev.). EEC stated that a specific sulfur specification could be produced by mixing higher and lower sulfur

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27/ Removal of approximately 91 to 92 percent of potential $SO_2$ emissions by the CFB technology would be in the range of removal anticipated by the Company. See Section II.B.2.a.ii.(A), below.

coals at the mines and that no additional costs would be incurred if coals were mixed at mines that had the equipment and manpower to blend coals as part of normal operation (Exh. HO-E-140, rev.; Tr. 18, p. 35).[28, 29]

(B) Company's Position

The Company asserted that its analysis of the availability, environmental impact and economic impact of lower sulfur coals fully addressed the requirements of the Siting Council (EEC Brief, pp. 6-7).

The Company also asserted that its analysis demonstrated that the most cost effective coals for the project would be from the Pennsylvania/Conrail region because transportation costs to the proposed site would be lowest from this region (Exh. HO-65A, EnviroFuels Report, p. 11).[30] However, the Company stated that the Pennsylvania/Conrail region, although containing abundant reserves of coal that would meet a 1.8 percent sulfur

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28/ EEC stated that the most cost-effective method of mixing higher and lower sulfur coals is to do so at the coal mine and load the mixed coal onto rail cars as one product (Exh. HO-140, rev.). EEC further stated that most mines have the equipment and manpower to mix coals as part of their normal operation (id.). EEC added that mixing coals at the proposed facility or an alternative site is also possible but would increase costs (id.).

29/ Mr. Henneke indicated that washing of raw coal was an additional means to reduce sulfur content but that washing of raw coal also would decrease the overall quantity of the coal by ten to 20 percent (Tr. 18, pp. 39-41, 127, 130-131). He estimated that it would cost approximately \$3 to \$5 per ton of coal to achieve a 0.3 to 0.4 percent reduction in coal sulfur content and noted that this cost estimate includes the cost of the additional amount of coal that would be required (id., pp. 130-131).

30/ The Company explained that the Pennsylvania/Conrail mines are the closest mines, geographically, to the proposed facility and would involve a single line haul to the proposed facility (Exh. HO-65A, EnviroFuels Report, pp. 11-12). The Company noted that rail transportation from this region would be \$20 to \$22 per ton of coal (id., p. 10).

specification, contains minimal reserves of lower sulfur coal (id.; Tr. 18, p. 11).[31] The Company stated that the least expensive lower sulfur coals would be from the central West Virginia and eastern Kentucky region (Exh. HO-65A, EnviroFuels Report, p. 11).[32] However, the Company stated that despite low incremental mine costs in a number of cases, these coals would not be cost-effective due to their significantly higher transportation costs (id.).[33]

EEC maintained that the results of its analysis demonstrated that the use of lower sulfur coal would not be cost-effective based on both the cost per ton for the $SO_2$ emission reductions that would be achieved, and the overall increase in costs for the project (Exh. HO-65A, pp. 2-3).[34] With regard to the cost to reduce a ton of $SO_2$ emissions through the use of lower sulfur coals, the Company stated that, even if the most

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31/ The Company stated that the lower sulfur coals from the Pennsylvania/Conrail region would have high incremental costs (Exh. HO-65A, EnviroFuels Report, p. 11).

32/ The Company indicated that the central West Virginia and eastern Kentucky region contains ample reserves of coal with sulfur content in the 0.8 percent to one percent range (Exh. HO-E-143). However, EEC predicted that the cost of these lower sulfur coals would increase, relative to higher sulfur coals, when the Clean Air Act Amendments of 1990 take effect (Exh. HO-65A, EnviroFuels Report, p. 11).

33/ EEC indicated that rail transportation from the central West Virginia and eastern Kentucky region, which would require transfers from CSX or N&W railroads to Conrail, would cost approximately $28 to $31 per ton of coal (Exh. HO-65A, EnviroFuels Report, p. 10). The Company noted that higher transportation costs of coals from this region are compounded by the cost of returning the ash to the mine site for disposal (id., p. 11).

34/ As noted in the previous section, the results of the Company's study were expressed, for each of the five coal regions, as the average (1) cost to reduce a ton of $SO_2$ emissions, relative to the emissions of a 1.8 percent coal, and (2) incremental total delivered cost, relative to the base-case coal.

cost-effective average lower sulfur coals were used at the proposed facility, $SO_2$ emission reductions would still cost approximately $6,000 per ton (id., EnviroFuels Report, p. 11). The Company stated that this cost exceeds the costs in the range of $3,000 to $5,000 per ton that have been considered by environmental agencies in New England to be cost-effective for the reduction of $SO_2$ emissions as part of their Best Available Control Technology ("BACT") reviews for new sources (Exh. AG-RR-32; Tr. 16, p. 61; EEC Brief, p. 8).

With regard to the cost impacts to the proposed facility, the Company provided a pro forma which included the increased operating costs of using the coal with the lowest incremental total cost, relative to the base-case coal, based on regional averages (Exh. HO-67C).[35] EEC indicated that its analysis demonstrated that the use of lower sulfur coal would render the proposed facility non-viable from a financial perspective because

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35/ The Company was requested to provide a pro forma which included the increased costs of using the study coal that had the lowest total cost and sufficient reserves needed to operate the proposed facility (Exh. HO-RR-100C). The pro forma indicated that the cost of using this study coal would be slightly higher than using the coal that had the lowest incremental total cost based on the regional averages, even though the study coal had a cost per ton of reduced $SO_2$ emissions that was half the cost per ton of reduced $SO_2$ emissions for the coal with the lowest incremental total cost based on regional averages (id., Exhs. HO-65C, HO-66).

Although the Company provided a pro forma for the study coal, the Company indicated that there is no basis for the Siting Council to conclude that any one mine will be a cost-effective and reliable source of coal because (1) it is not likely that a specific coal supplier would meet the quoted prices if such supplier was aware that one coal had been specified as the required fuel, and (2) there is no assurance that any one coal supplier would be willing or able to provide the level of reliability and performance guarantees necessary for a long-term contract (Exh. HO-65A, Envirofuels Report, p. 6; EEC Brief, p. 9).

the debt service coverage ratio and the return on equity would be reduced below acceptable levels (Exhs. HO-65D, HO-67C).[36, 37]

(C) Arguments of the Intervenors

The Attorney General argued that the Company did not comprehensively address the use of coal with a sulfur content less than 1.8 percent (Attorney General Brief, pp. 2-4). The Attorney General also argued that (1) the Company's conclusions that the use of lower sulfur coal would not be cost-effective, and (2) blending of coals with varying sulfur content to achieve a lower overall sulfur content would not be practical were contradicted by the Company's own analysis of lower sulfur coals (id., p. 3).

With regard to the use of lower sulfur coals, the Attorney General stated that the Company's analysis demonstrated that use of coal with a lower sulfur content than 1.8 percent was the most cost-effective fuel option for the proposed facility (id., pp. 5-6). The Attorney General also stated that the Company's analysis demonstrated that certain study coals with sulfur content below the base-case coal would be only marginally more expensive than the base-case coal and would result in further reductions in $SO_2$ emissions (id., p. 7).[38]

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36/ The Company did not specify the minimum return on equity that would be acceptable but indicated that, in general, most financial institutions would require a first year debt coverage ratio in excess of 1:1 and a 15 year average of 1.5:1 (Exhs. HO-E-147, HO-E-148).

37/ The Company also discussed the impacts of increased costs on its power purchase price (Exh. HO-65D).

38/ The Attorney General stated that the cost to reduce a ton of $SO_2$ emissions for a number of study coals, relative to a 1.8 percent sulfur coal, was within the range of costs that has been determined to be cost-effective for the purposes of BACT determinations (Attorney General Brief, pp. 8-9).

With regard to the blending of coals, the Attorney General stated that the Company's base-case coal is itself a blended coal and that the Company's coal procurement witness indicated that generally, coal blending would not increase costs (id., p. 9).

(D) Analysis

In this section, the Siting Council first determines whether the Company has provided a comprehensive analysis of the availability, environmental impact and economic impact of the use of coals with a range of sulfur contents below 1.8 percent as required by the condition in EEC. The record demonstrates that, in preparing its analysis of the use of lower sulfur coal, the Company solicited bids to supply the proposed facility with lower sulfur coal from the majority of the principal coal suppliers in the Pennsylvania, West Virginia, eastern Kentucky, Virginia, and Maryland coal-producing regions. Based on the response to its solicitation, the Company provided information regarding the location, available tons per year, characteristics, mine price, and transportation cost for 54 coals with sulfur contents ranging from 0.7 to 2.2 percent. In addition, the Company provided the total cost for each of the coals, the $SO_2$ emissions that would result from their use at the proposed facility and the cost to reduce a ton of $SO_2$ emissions, relative to a 1.8 percent sulfur coal. Finally, the Company considered mixing coals with varying sulfur contents.

Based on the foregoing, the Siting Council finds that the Company has complied with the condition in EEC to provide a comprehensive analysis of the availability, environmental impact and economic impact of the use of coal with a range of sulfur contents below 1.8 percent at the proposed facility.

The Siting Council next determines whether the use of 1.8 percent sulfur coal or a lower sulfur coal is consistent with the adequate minimization of $SO_2$ emissions at the proposed facility, while minimizing cost. In presenting the results of its analysis, the Company categorized the responses to its solicitation into five coal regions and averaged the additional cost of lower sulfur coal for each region. Based on the averaged results of the Company's analysis, the least expensive lower sulfur coal would add over $5 million to annual operating expenses and the cost of reducing an additional ton of $SO_2$ emissions would be in excess of $6,000 relative to a 1.8 percent sulfur coal. Therefore, considering only the averaged results, the use of lower sulfur coal may not be consistent with the adequate minimization of $SO_2$ emissions, while minimizing cost.

However, a review of the information compiled by the Company for specific study coals indicates that lowering the sulfur content of the coal used at the proposed facility may be a cost-effective means of reducing $SO_2$ emissions below 0.25 lb/MMBtu. First, the base-case coal, a blend of three different coals from two different mines, representing the most cost-effective coal in the Company's analysis, has a composite sulfur content of less than 1.8 percent and an $SO_2$ emission rate in the range of 0.20 lb/MMBtu to 0.213 lb/MMBtu. The Company's witness indicated that it would be feasible to use these three coals and that the Company would be willing to negotiate with coal suppliers for these three coals. Second, for a number of study coals, the cost to reduce $SO_2$ emissions by shifting to that coal would be in the range that the Company indicated would be considered cost-effective with respect to a BACT analysis.

In addition, in light of the testimony of the Company's witness that there would be no additional costs involved in blending coals of varying sulfur content at the mines and that the base-case coal would be a blend of coals from two different mines, there may be additional opportunities for the Company to blend coals of varying sulfur content in order to achieve a lower overall sulfur content in a cost-effective manner.

Based on the foregoing, the record demonstrates that the use of lower sulfur coal may be a viable option in order for the

Company to reduce the $SO_2$ emissions of the proposed facility in a cost-effective manner. Accordingly, the Siting Council finds that the use of lower sulfur coal may be consistent with the adequate minimization of $SO_2$ emissions from the proposed facility, consistent with the minimization of cost.[39]

In making this finding, the Siting Council notes the concern of the Company that none of the coal costs in its analysis of lower sulfur coal were negotiated prices and that such costs, as well as the availability of the individual coals are uncertain and, in fact, would likely be subject to change. Therefore, the Siting Council will not here specify a particular coal or blend of coals that EEC should use, but rather recognize that $SO_2$ emissions from the proposed facility can be adequately minimized consistent with minimizing cost through the use of certain coals with a sulfur content below 1.8 percent.

ii. Reduction in $SO_2$ Emissions through Facility Design and Operation

(A) Description

As an alternative to reducing the $SO_2$ emissions from the proposed facility by the use of lower sulfur coal, the Company proposed reducing $SO_2$ emissions by optimization of the design and operation of the CFB boiler (Exh. HO-65A, TA I, pp. 5-6). The Company stated that measures that potentially would reduce $SO_2$ emissions from the proposed facility include: (1) reinjecting

39/ The Siting Council notes that this finding is not inconsistent with the statement in EEC (see n.3, above) that if the Company fails to establish that environmental impacts will be adequately minimized, the Company's petition to construct the proposed facility will be rejected (22 DOMSC at 415 n.236). The Siting Council's finding here and in findings that follow acknowledge that there are several ways to achieve minimization of environmental impacts consistent with the minimization of cost.

coal ash;[40] (2) improving cycling design to maximize utilization of fuel and limestone within the combustion chamber; (3) grinding of coal and limestone into slightly finer particles to allow for more contact among particles; (4) optimizing sulfur-capture temperatures; and (5) increasing limestone injection (Exh. HO-E-132; Tr. 16, p. 10).

The Company indicated that the sulfur capture rates of the CFB technology have increased since the preparation of its original filing (Tr. 16, pp. 12-17).[41] The Company did not specify an exact sulfur capture rate but estimated that, based on use of 1.8 percent sulfur coal, actual $SO_2$ emissions from the proposed facility would be in the range of 0.23 lb/MMBtu to 0.24 lb/MMBtu (Tr. 17, p. 146).[42, 43]

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40/ Mr. Nawaz indicated that reinjection of coal ash would increase the carbon burnout, thereby increasing boiler efficiency and reducing fuel use (Tr. 16, pp. 32-33).

41/ The Company stated that the design of CFB boilers has been continually evolving (Tr. 16, pp. 10-11). The Company explained that, at the time its BACT analysis was initially prepared, the practical limitation on the CFB boiler sulfur capture rate was 90 percent but, since that time, CFB design has been improved and now the Company has assurances that the sulfur capture rate for the proposed facility would be in the 91.5 to 92 percent range (id., pp. 12-17). In addition, the Company indicated that vendors have been willing to guarantee higher sulfur capture rates based on the operating history of CFB facilities (Tr. 17, p. 141).

42/ The Company calculated that, based on the use of 1.8 percent sulfur coal, the $SO_2$ emission rate from the proposed facility would be (1) 0.25 lb/MMBtu, assuming 91 percent sulfur capture, and (2) 0.22 lb/MMBtu, assuming 92 percent sulfur capture (Exhs. HO-E-28, p. 5-51, HO-RR-94). Mr. Nawaz indicated that a boiler vendor would design the boiler based on the established emission limit instead of first committing to a specific sulfur capture rate for the proposed project (Exh. HO-E-133; Tr. 16, pp. 10-11).

43/ The Company stated that it would seek permit limits that would be higher than actual emission levels (Tr. 17, p. 142). The Company stated that boiler vendors would be subject to substantial financial penalties if guaranteed emission levels

(B) Company's Position

The Company asserted that a ten percent reduction in $SO_2$ emissions from 0.25 lb/MMBtu to 0.225 lb/MMBtu could be achieved from the proposed facility by pushing the CFB technology to its limit (Tr. 17, pp. 108, 114-115). The Company also asserted that optimization of the operation of the CFB boiler would be a more cost-effective means of lowering $SO_2$ emissions than use of lower sulfur coal (Exh. HO-65A, TA I, p. 6).[44, 45] The Company further asserted that its proposal to implement an optimization approach to reduce $SO_2$ emissions by ten percent is consistent with the objectives of the Siting Council (EEC Brief, p. 13).

(C) Arguments of the Intervenors

The Attorney General noted that an emission rate less than 0.25 lb/MMBtu can be achieved at the proposed facility, even with the use of 1.8 percent sulfur coal (Attorney General Brief,

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were exceeded and, thus, a "cushion" would be maintained between actual and guaranteed levels to ensure that emissions do not exceed permit levels (id., pp. 142-143). The Company noted that the "cushion" might be reduced with a higher sulfur capture rate (Tr. 20, p. 162).

44/ Although the Company maintained that the increased costs to achieve a ten percent reduction in $SO_2$ emissions via technological approaches would maintain the financial viability of the proposed project, the Company stated that it could not estimate such costs (Tr. 16, pp. 29-33, Tr. 17, pp. 114-115, 129).

45/ The Company stated that the determination of the specific technological approaches to reduce $SO_2$ emissions that would be most cost-effective would be made in conjunction with the boiler vendor in the final design stages of the facility (Tr. 16, pp. 77-78). However, the Company indicated that attaining a ten percent reduction in emissions from the proposed facility would not be as efficient as subsidizing other facilities that do not utilize technology as advanced as the CFB technology (see Section II.B.2.a.iii, below) (id., pp. 112-114).

p. 10).[46] NO-COAL argued that the Company did not present any hard evidence or manufacturers' guarantees to ensure that the sulfur capture rate of the proposed facility could be increased (NO-COAL Brief, p. II-1).

(D) Analysis

The record demonstrates that an $SO_2$ emission rate of 0.225 lb/MMBtu, which represents a ten percent decrease in $SO_2$ emissions from the $SO_2$ emission rate of 0.25 lb/MMBtu originally proposed by the Company, could be achieved at the proposed facility, even with the use of 1.8 percent sulfur coal. The sulfur capture rates of CFB facilities have generally improved since the Company prepared its original petition. In addition, EEC has suggested a number of measures that could be incorporated into the design of the proposed facility that would optimize boiler operation to reduce $SO_2$ emissions and has agreed to achieve a ten percent reduction in $SO_2$ emissions beyond the level originally proposed. The record demonstrates that with these measures, the sulfur capture rate of the proposed facility would likely be in the 91.5 to 92 percent range.

Although the Company could not specify the cost implications of a ten percent reduction in $SO_2$ emissions by optimization of boiler design and operation, the record demonstrates that such a decrease in $SO_2$ emissions very likely could be accomplished without impacting the financial viability of the proposed facility.[47]

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46/ The Attorney General argued that the determination of BACT is driven predominantly by the limits that are, in fact, achievable by the use of a given fuel and technology and that BACT for $SO_2$ for the proposed facility would therefore likely be lower than 0.25 lb/MMBtu (Attorney General Brief, p. 10).

47/ With regard to the argument of the Attorney General that BACT for $SO_2$ for the proposed facility would be lower than 0.25 lb/MMBtu, the Siting Council notes that BACT will be determined by the DEP.

Based on the foregoing, the Siting Council finds that a ten percent decrease in the $SO_2$ emission rate to 0.225 lb/MMBtu would be consistent with an adequate minimization of the $SO_2$ emissions from the proposed facility, consistent with the minimization of cost.

iii. Emission Reduction from Other Facilities

(A) Description

As an alternative to reducing $SO_2$ emissions by ten percent from the proposed facility by technological means, EEC proposed to subsidize a reduction of 300 tpy in $SO_2$ emissions from other electric generating facilities in Massachusetts (Tr. 17, pp. 107-111, Tr. 19, pp. 34-40). The Company stated that the source of such a subsidy would be the cost savings it could achieve if no limitation were placed on the sulfur content of the coal utilized at the proposed facility and coal with a sulfur content greater than 1.8 percent was utilized at the proposed facility (id.). EEC indicated that the rationale for the 300-ton threshold was that it represents approximately ten percent of the proposed facility's $SO_2$ emissions and the facility itself could be "pushed" to attain a further ten percent reduction in emissions if the offset program proved to be unworkable (Tr. 19, pp. 40, 53).[48]

The Company explained that the subsidies would be provided to electric utilities which would achieve reductions in $SO_2$ emissions by purchasing higher cost, lower sulfur fuels than they currently use, or by adding post-combustion controls to their

48/ EEC estimated that 3,367 tpy of $SO_2$ would be emitted from the proposed facility, assuming 92 percent plant availability (Exh. HO-E-128, Table 128A). The Siting Council notes that a ten percent reduction in emissions would therefore be approximately 330 tpy.

existing generating facilities (Tr. 17, pp. 111-112, 54).[49, 50]

(B) Company's Position

The Company stated that a reduction in $SO_2$ emissions from other sources is a reduction that could be accomplished without additional cost to the proposed facility (id., pp. 62-66).[51] The Company maintained that the CFB technology was designed to utilize higher sulfur coals, and that, therefore, the benefits of the CFB technology would be maximized with the use of higher sulfur coals (Tr. 17, pp. 111-112).[52] The Company asserted

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49/ The Company's original proposal was to subsidize $SO_2$ emission reductions at other facilities with the entire amount of cost savings that would be realized from use of higher sulfur coal rather than 1.8 percent sulfur coal at the proposed facility (Tr. 17, pp. 114, 117). The Company stated that this proposal would achieve at least a 300-ton reduction in overall emissions in Massachusetts (id.).

In response to anticipated regulatory and implementation concerns, the Company then amended its original proposal to set a specific reduction in $SO_2$ emissions (Tr. 19, pp. 38-40). Thus, the Company proposed to reduce $SO_2$ emissions by 300 tons per year, either from its own facility or from subsidizing emission reductions at other facilities (id., Tr. 20, pp. 13-14). The Company maintained that its incentive was not to add to its return on equity and that if it could provide $SO_2$ emission offsets in excess of 300 tons per year from other facilities, it was prepared to do so (Tr. 17, p. 124, Tr. 20, p. 34).

50/ The Company noted that under certain $SO_2$ emission reduction strategies, i.e., fuel switching from oil to gas, $CO_2$ emissions also would be reduced (Tr. 20, p. 166).

51/ Mr. Croyle stated that the Company would go forward with the proposed facility if the Siting Council imposed a limit of 0.225 lbs/MMBtu of $SO_2$, but that this limitation (1) would not be an efficient means of lowering overall $SO_2$ emissions within Massachusetts, and (2) would impact the facility's return on equity (Tr. 17, pp. 128-130).

52/ The Company noted that the sulfur capture rates of the CFB technology increase with increased sulfur input (Tr. 17, p. 128).

that the coal cost savings from the use of coal with a sulfur content greater than 1.8 percent would achieve a greater reduction in $SO_2$ emissions from other facilities than the reduction in $SO_2$ emissions that could be achieved at the proposed facility through the use of lower sulfur coals or optimization of the operation of the CFB boilers (id., p. 116).[53] As an example of the benefits that could be achieved under its proposal, the Company stated that savings of approximately $1.5 million per year from the use of a 2.4 percent sulfur coal instead of 1.8 percent sulfur coal would subsidize emission reductions of 300 to 600 tpy at other facilities (Tr. 17, p. 110, Tr. 20, pp. 35, 157).

The Company also provided a preliminary analysis which showed that the cost to reduce a ton of $SO_2$ emissions at two existing electric generating facilities would range from $400 to $1300, based on (1) the current fuel costs at the two facilities, and (2) the cost of fuels with lower sulfur contents (Exh. HO-RR-74). The Siting Council notes that, based on the Company's estimated annual fuel savings of $1.5 million from use of 2.4 percent sulfur coal instead of 1.8 percent sulfur coal, the reduction in $SO_2$ emissions from the two existing electric

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53/ EEC stated that it would cost more to remove a ton of $SO_2$ emissions from the proposed facility where the environmental controls are integral to the technology than it would cost to remove a ton of $SO_2$ emissions from an existing facility where $SO_2$ emissions are controlled by sulfur input rather than technology (Tr. 17, p. 121, Tr. 18, pp. 90-91). Mr. Henneke explained that the CFB boiler already captures approximately 11/12ths of the sulfur in the coal and that, therefore, it is significantly more cost effective to utilize lower sulfur coals in facilities without technology to decrease $SO_2$ emissions (Tr. 18, pp. 90-91). As an example, Mr. Henneke identified two existing facilities where a 300-ton decrease in $SO_2$ emissions could be achieved by the substitution of a small amount of 0.7 percent sulfur coal for the facility's usual coal (Tr. 18, pp. 132-133).

generating facilities could range from 1,150 to 3,750 tpy (see id.).[54]

The Company also maintained that the $SO_2$ emission rate of 0.25 lb/MMBtu, which was proposed in its original petition in conjunction with utilization of 1.8 percent sulfur coal, would not increase with the use of higher sulfur coal, and that the originally proposed permit levels for all other regulated pollutants, likewise, would not increase (Exh. HO-E-28, p. 5-51; Tr. 17, p. 120, Tr. 19, pp. 47-48, 55).[55] The Company asserted that actual emissions would be less than permitted emission levels no matter which coal is utilized and that actual emissions would not be closer to permit maximums if higher sulfur coal were utilized (Tr. 19, p. 52).

With regard to the impact of its proposal on the $SO_2$ emission reductions that will be required under the 1990 amendments to the Clean Air Act, the Company stated that it would be a policy issue whether its subsidies to utilities for application to their existing facilities would be used to reduce emissions to (1) levels that eventually will be required under the Clean Air Act, thereby providing benefits to ratepayers, or (2) levels below those that will be required under the Clean Air Act, thereby providing additional environmental benefits (Tr. 17, p. 110, Tr. 20, pp. 14-17).

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54/ The Company indicated that a number of utilities have expressed interest in the proposal after preliminary discussions (Tr. 17, pp. 133-134).

55/ The Company indicated that increasing the coal sulfur content from 1.8 percent to 2.4 percent would increase limestone requirements and that increased limestone would lead to: (1) an increase in $CO_2$ emissions of approximately one percent; (2) a slight increase in carbon monoxide ("CO") emissions; and (3) increased ash production (Exhs. HO-RR-77, AG-RR-36; Tr. 19, p. 43). The Company noted that the permit level for CO would not be exceeded nor would an increase in the permit level be requested (Exh. AG-RR-36).

Finally, EEC maintained that it was not essential for the purposes of this compliance proceeding for the Siting Council to determine the details of implementation of the Company's offset proposal (EEC Brief, pp. 14-15). EEC stated that the Siting Council should give EEC the flexibility to achieve the reduction in the most cost-effective way possible, including offsets at other facilities (id., p. 15).

(C) Arguments of the Intervenors

The Attorney General argued that the Company should not be permitted to offset its own $SO_2$ emissions by subsidizing reductions in $SO_2$ emissions from other facilities (Attorney General Brief, pp. 14-20). The Attorney General further argued that, instead, EEC should be required to minimize the emissions from the proposed facility to the lowest cost-effective levels (id., pp. 14-15). The Attorney General stated that EEC's proposal would allow the $SO_2$ emissions from the proposed facility to remain at artificially high levels while shifting the responsibility for minimizing emissions to other power plants (id.).[56]

In addition, the Attorney General argued that a broad array of critical policy issues, including mechanisms to ensure

56/ The Attorney General stated that the offset proposal would not guarantee that the air will ultimately be cleaner than it would be if each power plant individually reduced its own emissions to the lowest cost-effective levels (id.). The Attorney General also stated that the offset policy may not be in the best interest of the Commonwealth in that the availability of offsets would encourage their use in place of pollution controls which could result in many lost conservation opportunities due to lower electricity costs (id., p. 15).

its viability[57] and enforceability, must be determined prior to the implementation of an offset approach (id., pp. 14, 17-19). The Attorney General maintained that implementation of such a program would require clearly defined oversight by the appropriate governmental agencies to monitor that the proposed $SO_2$ emissions offsets are indeed incremental and guarantee that offsets will last for at least the same period of time as the pollution that it is offsetting will last (id., pp. 19-20).[58]

Finally, the Attorney General suggested that EEC's motivation for pursuing the offsets approach is that it would provide EEC with economic benefits in that the expected costs of attaining $SO_2$ emissions offsets at other facilities would be the same or lower than the fuel cost savings that the Company would achieve if allowed to use cheaper, higher sulfur coal (id., p. 16).[59]

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57/ The Attorney General stated that the viability of the emissions offsets proposal is uncertain because the structure and costs of such a program have not been determined (Attorney General Brief, pp. 18-19). The Attorney General stated that the Company has not fully considered, in conjunction with the DEP, a means to ensure that the desired results from utilities and other independent power producers are achieved or how offsets could apply to the local area where the proposed facility would have the greatest impacts (id.). In addition, the Attorney General stated that the Company has not estimated the cost of initiating such a program or the amount of the Company's contribution (id.).

58/ The Attorney General stated that enforcement of such a program would be complex and expensive and would require increased staffing levels at agencies such as the DEP (Attorney General Brief, p. 19).

59/ The Attorney General stated that the Company would receive an additional financial advantage because it would not be required to pass on fuel savings to the ratepayers through a cost of power adjustment (Attorney General Brief, p. 16). Thus, the Attorney General stated that EEC would be able to retain the benefits of an offsets arrangement while the utilities' ratepayers would pay for higher fuel costs through cost of power adjustments (id.).

NO-COAL argued that the Company's strategy for the reduction of $SO_2$ emissions from other fossil fuel facilities (1) would fail to minimize the $SO_2$ emissions from the proposed facility, and (2) has the potential to burden ratepayers with increased power costs (NO-COAL Brief, p. IV-1).[60] NO-COAL stated that: (1) each proposed new power plant should stand on its own merit to meet the criteria of minimal environmental impact; (2) existing facilities should be encouraged to reduce their overall $SO_2$ emissions in accordance with the intent of the Clean Air Act mandates; and (3) strict limitations on the percentage of sulfur in fuel, stack emissions, and total tons per year of sulfur emissions be placed on the proposed facility (id.). NO-COAL also argued that the $SO_2$ offsets proposal was simply a business deal that would provide substantial economic benefit to EEC (id., pp. II-2, II-3, II-4).

(D) Analysis

The record demonstrates that the Company could achieve the $SO_2$ emission rate of 0.25 lb/MMBtu, proposed in conjunction with the use of 1.8 percent sulfur coal, even if coal with a sulfur content in excess of 1.8 percent were utilized at the proposed facility. In addition, the record demonstrates that the Company could realize significant cost savings if coal with a sulfur content in excess of 1.8 percent were utilized at the proposed facility. Such cost savings could subsidize reductions in $SO_2$ emissions at existing electric generating facilities which, in turn, would offset a portion of the $SO_2$ emissions from the proposed facility. The record further demonstrates that such subsidies have the potential to achieve greater reductions in $SO_2$

60/ NO-COAL stated that if a utility's fuel costs increased, i.e., due to EEC's payment to purchase lower sulfur coal, that utility's power purchasers would pay higher costs and that facility would slip lower in the New England Power Pool ("NEPOOL") economic dispatching order while EEC's economic dispatching order would improve (NO-COAL Brief, p. II-3).

emissions in a cost-effective manner at existing electric generating facilities than the reduction in $SO_2$ emissions that can be achieved at the proposed facility.

In evaluating the Company's proposal to offset higher $SO_2$ emission rates at the proposed facility by arranging to reduce $SO_2$ emissions from other electric generating facilities, the Siting Council recognizes that, in implementing its mandate to ensure a necessary energy supply for the Commonwealth with least cost and least environmental impact, it must consider the overall environmental impacts on the Commonwealth. However, we also recognize that the Siting Council always has required that the environmental impacts of individual projects at specific sites be adequately minimized consistent with cost.

With respect to the proposed facility, the Siting Council notes that, under the Company's proposed offset approach, the Company would not achieve an $SO_2$ emission rate of 0.225 lb/MMBtu but would achieve an $SO_2$ emission rate of 0.25 lb/MMBtu at the proposed facility. Therefore, under such an offset approach, actual $SO_2$ emissions at the proposed facility would not be adequately minimized as discussed the previous two sections. However, the potential to achieve higher overall emission reductions in the Commonwealth as a whole, represents a potential societal benefit that cannot be overlooked. Clearly, a greater return in environmental protection without increasing costs furthers the goal of the Siting Council in ensuring a least-cost, least environmental impact energy supply for the Commonwealth. Therefore, an emissions offset approach that would trade potentially higher $SO_2$ emissions at a proposed facility for lower $SO_2$ emissions at existing facilities, resulting in significantly greater emission reductions than the emission reductions that could be achieved at that proposed facility, within the constraints of existing technology and economic viability, represents an acceptable theoretical approach for the minimization of environmental impacts within the context of our overall mandate.

However, we agree with the Attorney General and NO-COAL that significant policy and practical considerations exist in regard to implementing such an approach.[61] In particular, we must first assure that the emissions from the proposed facility meet all applicable standards and would not result in unacceptable impacts at the proposed site. Second, in light of the increased impacts at the proposed site, we must determine the extent of emissions offsets that would be appropriate, and the extent of such offsets, if any, that should apply to the local area of the proposed facility. Third, we must ensure that an emissions offset program would be acceptable to the DEP or other appropriate state agency(s) and result in verifiable, quantifiable emissions offsets for the operating life of the proposed facility. Finally, an emissions offset program also must result in incremental emission reductions, over and above any emissions reductions that would occur without the implementation of such a program, i.e., emissions reductions that would occur under the 1990 Amendments to the Clean Air Act or other federal or state regulations, or as a result of other factors such as planned facility retirements.

In evaluating EEC's proposal against these considerations, the Siting Council first reviews the impact of an $SO_2$ emission rate of 0.25 lb/MMBtu from the proposed facility. In EEC, the Company established that facility $SO_2$ emissions, based on an $SO_2$

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61/ With respect to the arguments of the Attorney General and NO-COAL that an emissions offset approach would result in (1) higher rates for utility ratepayers, and (2) changes in the order of NEPOOL dispatch of generating facilities, the Siting Council notes that there is nothing in the record of this proceeding that supports these arguments.

The record also does not support the Attorney General's argument that the availability of offsets would encourage, or even allow, their use in place of pollution controls (see n.56, above).

emission rate of 0.25 lb/MMBtu, would not only comply with all applicable federal and state air quality standards, but would result in ambient air concentrations significantly below all such federal and state standards (22 DOMSC at 351-354, Tables 6,7,8).[62] In addition, under the proposed offset program, there would be no increase in the emission levels for any regulated pollutants at the proposed facility over the permit levels determined in conjunction with an $SO_2$ emission rate of 0.25 lb/MMBtu based on use of 1.8 percent sulfur coal. As such, emissions from the proposed facility would not result in unacceptable impacts at the site. Therefore, it is acceptable to consider the Company's emission offset proposal.

In determining the extent of offsets that would be appropriate, we must first consider the emission reduction that could be achieved at the proposed facility in a cost-effective manner. In light of the Siting Council's previous finding that a reduction in the $SO_2$ emission rate by ten percent from 0.25 lb/MMBtu to 0.225 lb/MMBtu would represent adequate minimization of the $SO_2$ emissions from the proposed facility while minimizing costs, an emissions offset approach would be beneficial to the Commonwealth and, therefore, acceptable, only if it resulted in emissions reductions beyond the ten percent emission reduction that could be achieved at the proposed facility for a similar or lower cost. Further, in light of the incremental impact at the proposed site, at a minimum, a doubling of the emission reduction that could be achieved at the proposed

62/ In reviewing the impact of facility $SO_2$ emissions based on an emission rate of 0.25 lb/MMBtu, the Siting Council notes that the facility impact is greatest with reference to the 24-hour $SO_2$ ambient concentration (22 DOMSC at Table 6, Table 7). However, the Siting Council further notes that facility emissions at this emission rate, combined with background concentrations, would be 48 percent of National Ambient Air Quality Standards and would account for only 22 percent of Prevention of Significant Deterioration Standards for the 24-hour $SO_2$ averaging period. Id.

facility, an emission reduction of 660 tpy,[63] would be consistent with an adequate minimization of the $SO_2$ emissions from the proposed facility, consistent with the minimization of cost.[64] Finally, in order to ensure that the local area receives comparable environmental protection to that which it would have received if the emissions of the proposed facility were reduced by ten percent, emissions offsets of at least 330 tpy of the 660 tpy emission reduction should be attained in as close proximity to the proposed site as possible.[65]

Accordingly, based on the foregoing, the Siting Council finds that an $SO_2$ emissions offset program that would result in a decrease in $SO_2$ emissions from existing electric generating facilities in Massachusetts of at least 660 tons per year, with at least 330 tons per year from electric generating facilities in southeastern Massachusetts, would be consistent with an adequate minimization of the $SO_2$ emissions from the proposed facility, consistent with minimization of cost, provided that the program: (1) costs no more than the costs of achieving an emission rate at the proposed facility of 0.225 lb/MMBtu with use of 1.8 percent

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63/ As noted above, a ten percent reduction in $SO_2$ emissions would be approximately 330 tpy (see n.16, above).

64/ The Siting Council notes that, although the record is not complete with respect to the maximum level of offsets that could be achieved by EEC under an emissions offsets program, a minimum reduction of 660 tpy is well within the range of offsets that the Company estimated that it could achieve with the cost savings identified. As noted above, EEC estimated that it could achieve emissions reductions at other facilities in the range of 300 to 600 tpy, but a preliminary analysis by the Company also demonstrated that there is the potential to achieve far greater emissions reductions at other facilities (see Section II.B.2.a.iii.(B), above).

The Siting Council further notes that any reduction in emissions from other facilities above 660 tpy as a result of the offset program would not necessarily have to be incremental.

65/ The Siting Council notes that southeastern Massachusetts has several existing electric generating facilities which may be appropriate candidates for such a program.

sulfur coal; (2) is acceptable to the DEP or other appropriate state agency(s); (3) would result in verifiable, quantifiable $SO_2$ emissions offsets for the operating life of the proposed facility; (4) would not require increases in emission levels for any regulated pollutants at the proposed facility over any permit levels determined in conjunction with an emission rate of 0.25 lb/MMBtu based on the use of 1.8 percent sulfur coal; and (5) would result in incremental emission reduction benefits.

In making this finding, the Siting Council recognizes that the DEP may establish a maximum $SO_2$ emission rate for the proposed facility below 0.25 lb/MMBtu. In this event, it would be appropriate for an emissions offset program to achieve total offsets for twice the excess of the annual $SO_2$ emissions that would result from the emission rate accepted by DEP and those that would result from an emission rate of 0.225 lb/MMBtu, determined on the basis of 92 percent plant availability. Further, under such a scenario, a comparable one-half portion of the emission offsets should occur in southeastern Massachusetts.

iv. Conclusions on $SO_2$ Emissions

The Siting Council has found that the Company complied with the condition in EEC to provide a comprehensive analysis of the availability, environmental impact and economic impact of the use coal with a range of sulfur contents below 1.8 percent at the proposed facility. The Siting Council also has found that the use of lower sulfur coal may be consistent with the adequate minimization of $SO_2$ emissions from the proposed facility, consistent with the minimization of cost.

In addition, the Siting Council has found that a ten percent decrease in the $SO_2$ emission rate to 0.225 lb/MMBtu would be consistent with an adequate minimization of the $SO_2$ emissions from the proposed facility, consistent with minimizing cost.

Finally, the Siting Council has found that an $SO_2$ emissions offset program that would result in a decrease in $SO_2$

emissions from electric generating facilities in Massachusetts of at least 660 tons per year, with at least 330 tons per year from electric generating facilities in southeastern Massachusetts, would be consistent with an adequate minimization of the $SO_2$ emissions from the proposed facility, consistent with minimization of cost, provided that the program: (1) costs no more than the costs of achieving an emission rate at the proposed facility of 0.225 lb/MMBtu with use of 1.8 percent sulfur coal; (2) is acceptable to the DEP or other appropriate state agency(s); (3) would result in verifiable, quantifiable $SO_2$ emissions offsets for the operating life of the proposed facility; (4) would not require increases in emission levels for any regulated pollutants at the proposed facility over any permit levels determined in conjunction with an emission rate of 0.25 lb/MMBtu based on the use of 1.8 percent sulfur coal; and (5) would result in incremental emission reduction benefits.

In sum, the Company's original proposal to utilize 1.8 percent sulfur coal to achieve an $SO_2$ emission rate of 0.25 lb/MMBtu does not represent adequate minimization of $SO_2$ emissions. However, there are a number of options that EEC may undertake that would adequately minimize $SO_2$ emissions, consistent with the minimization of cost. The Company can reduce $SO_2$ emissions from the proposed facility from 0.25 lb/MMBtu to 0.225 lb/MMBtu or less by use of coal with a sulfur content below 1.8 percent, by optimization of the design and operation of the CFB boiler, or by a combination of both methods. In the alternative, the Company can minimize the $SO_2$ emissions from the proposed facility by arranging to reduce at least 660 tpy of $SO_2$ emissions from other generating facilities in Massachusetts, or a reduction consistent with the discussion above if the DEP determines BACT for the proposed facility to be less than 0.25 lb/MMBtu. The Siting Council recognizes that the Company can best determine which option would be most cost-effective in minimizing the $SO_2$ emissions from the proposed facility.

Therefore, the Siting Council will allow the Company to decide which option to pursue.

Accordingly, based on the foregoing, the Siting Council finds that if EEC adopts one or more of the above discussed methods for mitigating $SO_2$ emissions, the $SO_2$ emissions from the proposed facility would be adequately minimized, consistent with minimization of cost.

b. $CO_2$ Emissions

In EEC, the Siting Council found that the Company had failed to establish that $CO_2$ emissions from the proposed facility had been adequately minimized (22 DOMSC at 360). The Siting Council noted that, although the Company indicated that it would participate voluntarily in the Massachusetts ReLeaf Program ("MASS ReLeaf"), the record did not indicate the extent of the Company's participation or the costs involved. Id. Nevertheless, the Siting Council recognized that a comprehensive analysis of the economic and environmental impacts of attaining a range of $CO_2$ offsets -- through participation in MASS ReLeaf or though other methods -- may have allowed the Company to demonstrate that, with its plan for attaining $CO_2$ offsets, $CO_2$ emissions were adequately minimized. The Siting Council indicated that this analysis should include: (1) the $CO_2$ emission offsets that would be achieved under EEC's plan for participation in MASS ReLeaf and the costs associated with the plan; (2) a range of $CO_2$ emissions offsets that could be attained through participation in the MASS ReLeaf program or by other methods; and (3) the costs of attaining different levels of $CO_2$ emission offsets and the impact of such costs on the financeability of the project and the ability of the Company to market power from the facility. Id. at 360-361. The Siting Council found that if (a) the Company provided a plan for attaining $CO_2$ emission offsets through participation in MASS ReLeaf or other methods and a comprehensive analysis of the economic and environmental impacts of attaining a range of $CO_2$ emission offsets, and (b) the Siting Council determined, after review, that the Company's plan for attaining $CO_2$ emission offsets or a different $CO_2$ emission offset plan was consistent with the minimization of $CO_2$ emissions, then $CO_2$ emissions would be adequately minimized. Id. at 362.

In response, the Company provided an analysis of the environmental and economic impacts of attaining $CO_2$ offsets through its proposed participation in MASS ReLeaf and of attaining a range of $CO_2$ offsets through other methods. In this section, the Siting Council reviews the Company's analysis to determine (1) whether the Company has provided a comprehensive analysis of the economic and environmental impacts of attaining a range of $CO_2$ emission offsets, and (2) whether the Company's plan for attaining $CO_2$ emission offsets or a different $CO_2$ emission offset plan would be consistent with the minimization of $CO_2$ emissions.

i. Description

In order to mitigate $CO_2$ emissions from the proposed facility, EEC proposed to attain $CO_2$ offsets by participation in MASS ReLeaf, a state program that solicits donations for the planting of shade trees throughout the state (Exhs. HO-65A, p. 4, NC-29).[66] The Company proposed an annual contribution of \$30,000 to MASS ReLeaf for 40 years, which would total \$1.2 million over the projected 40-year life of the proposed facility (Exh. HO-65A, p. 4). The Company indicated that its contribution to MASS ReLeaf would offset facility $CO_2$ emissions because non-mature trees absorb more carbon than they produce, and thus, remove $CO_2$ from the atmosphere (Exhs. HO-65, TA II, exh. A, pp. 1-2, NC-29). The Company estimated that its

66/ MASS ReLeaf is associated with Global Releaf, a program to plant trees sponsored by the American Forestry Program (Exh. NC-29).

contribution to MASS ReLeaf would offset approximately 9,000 tpy or 0.4 percent of annual facility $CO_2$ emissions and would cost \$3.33 per ton of $CO_2$ offsets (Exhs. HO-RR-84, NC-RR-7).[67, 68]

In addition, the Company provided an analysis of the feasibility, availability and cost of five alternative approaches to offset $CO_2$ emissions, as follows: (1) reforestation; (2) forest preservation; (3) automobile emissions reduction; (4) destruction of chlorofluorocarbons ("CFCs") from auto air conditioners ("CFC approach"); and (5) methane extraction from landfills ("methane approach") (id.).

The Company stated that the approach of reforestation, by planting seedlings, would also provide $CO_2$ emissions offsets via the carbon absorption potential of growing trees (Exh. HO-65A, TA II, exh. A, pp. 1-2).[69] The Company indicated that the cost to reduce $CO_2$ emissions by reforestation would be \$2.00 per ton of reduced $CO_2$ emissions (id., Table A). The Company indicated that the cost of a reforestry program was derived from public information regarding a Guatemalan reforestation project designed to offset the $CO_2$ emissions from the Applied Energy Services ("AES") Thames facility, a 183 megawatt coal-fired generating facility in Uncasville, Connecticut (Exh. HO-65A, TA II, exh. A,

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67/ As the basis of its calculation, the Company assumed that its contribution to MASS ReLeaf would provide for 300 trees at \$100 per tree for each of the 40 years and that each newly planted tree would absorb 30 tons of $CO_2$ (Exhs. NC-RR-7, NC-28).

68/ The Company noted that approximately 50 acres would be cleared to construct the proposed facility requiring removal of approximately 15,000 trees (Exh. AG-RR-40). The Company's calculation of the $CO_2$ emission offset potential of its contribution to MASS ReLeaf did not account for this loss of trees from the site (Exhs. NC-RR-7, NC-28).

69/ The Company noted that, although a mature forest achieves a balance of $CO_2$ intake and production, a net removal occurs in a developing forest because, as a tree continues to grow, the carbon contained in its biomass increases (Exh. HO-65A, TA II, exh. A).

p. 2). The Company indicated that the Guatemalan reforestation project is sponsored by AES and public agencies and will offset 100 percent of the facility emissions (Exh. AG-RR-41). The Company noted that, of the $18.3 million cost of the project, AES contributed $2 million and the remaining amount was contributed by various public agencies (Exh. HO-65A, TA, exh. A, p. 2). The Company estimated that its $1.2 million contribution to MASS ReLeaf would offset approximately 15,000 tpy or 0.58 percent of annual facility $CO_2$ emissions if applied to a reforestation approach (Exh. HO-RR-83).[70]

EEC stated that both the forest preservation and automobile emissions reduction approaches would offset $CO_2$ emissions by preventing the release of $CO_2$ into the atmosphere (Exh. HO-65A, TA II, exh. A, pp. 2-3). With respect to forest preservation, the Company stated that such an approach would involve the purchase and protection of a tract of forested land that would otherwise be converted to a land use with a lesser amount of carbon storage potential (id., p. 2). EEC assumed that the cost of a forest preservation approach would be equal to the cost of a reforestry approach (id., p. 3). With respect to automobile emissions reductions, the Company indicated that since automobile emissions are a source of $CO_2$, a reduction in the number of vehicle-miles travelled would be a means of reducing $CO_2$ emissions (id.). The Company estimated that it would cost $200 to reduce a ton of $CO_2$ emissions in this manner (id., Table 1, Exh. HO-E-171). In addition, EEC estimated that its $1.2 million proposed contribution would offset 150 tpy or 0.01 percent of annual facility $CO_2$ emissions if applied to an automobile emissions reduction approach (Exh. HO-RR-83).

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70/ The Siting Council notes that because reforestation would involve the planting of a large number of seedlings at one time, while MASS ReLeaf would involve the planting of trees on an individual basis, costs per tree would be less under reforestation (see Exhs. NC-29, AG-RR-41).

Finally, the Company noted that other gases, including CFCs and methane, have heat absorption effects in the atmosphere exceeding those of $CO_2$, and that $CO_2$ offsets, therefore, could be effectively attained by preventing the release of these substances into the atmosphere (Exh. HO-65A, TA II, exh. A, p. 3).[71] The Company stated that an existing source of CFC emissions is discarded automobile air conditioners and that destruction of these CFCs would prevent their release (id.).[72] The Company also stated that an existing source of methane production is landfills and that methane emissions could be reduced by the reuse or destruction of such methane (id., p. 5). The Company estimated that the cost to offset a ton of $CO_2$ would be 60 cents under a CFC approach[73] and approximately $2.00 under a methane approach (Exh. HO-E-171).[74] The Company further estimated that its proposed contribution of $1.2 million would offset approximately 50,000 tpy or 1.92 percent of annual facility $CO_2$ emissions if applied to a CFC approach and

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71/ The Company noted that one pound of CFCs has the same heat absorption effect as approximately 4.5 tons of $CO_2$, and that 100 pounds of methane has the same heat absorption effect as one ton of $CO_2$ (Exh. HO-65A, TA II, exh. A, pp. 3, 5).

72/ The Company noted that recently proposed United States Environmental Protection Agency ("EPA") requirements mandate the recycling of CFCs from automobile air conditioners (Exh. HO-65A, TA II, exh. A., p. 3). The Company noted that, therefore, an alternative to CFC destruction would be curtailment of CFC generation (id.).

73/ The Company stated that the costs for the CFC program were based on the acquisition of used CFC refrigerant from discarded auto air conditioners, incineration costs and an adjustment to a $CO_2$ equivalent (Exh. HO-E-171).

74/ The Company indicated that costs were based on the quantity of methane potentially extractable, capital equipment requirements and an adjustment to a $CO_2$ equivalent (Exh. HO-E-171). The Company noted that, although $CO_2$ would be emitted in the destruction or reuse of methane, such $CO_2$ emissions were not taken into account in the determination of costs (Exh. HO-RR-91).

approximately 14,600 tpy or 0.56 percent of annual facility emissions if applied to a methane approach (Exh. HO-RR-83).

The Company also estimated the cost of offsetting five, ten, 20 and 100 percent of facility emissions under a contribution to MASS ReLeaf and each of the alternative $CO_2$ offset approaches (Exhs. HO-E-150, HO-E-171). The Company noted that under the CFC approach, the least costly means to offset $CO_2$ emissions, costs would be: (1) $3.1 million for a five percent offset; (2) $6.2 million for a ten percent offset; and (3) $62.5 million for a 100 percent offset (Exh. HO-E-150).

ii. Company's Position

The Company asserted that its proposed contribution to MASS ReLeaf adequately minimizes the $CO_2$ emissions from the proposed facility (EEC Brief, pp. 16-20). In support, the Company asserted that its proposal not only addresses the Siting Council standard for $CO_2$ mitigation set forth in Enron, but also significantly exceeds the precedent for $CO_2$ mitigation set by the Siting Council's acceptance of Enron's proposed $CO_2$ mitigation (id., pp. 17-19; Exh. HO-65A, TA II, p. 2).[75, 76] EEC stated that an additional reason its proposed $CO_2$ mitigation is adequate

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75/ The Company stated that in requiring EEC to provide a comprehensive analysis supporting a plan for attaining $CO_2$ emission offsets, the Siting Council acknowledged that it had never required applicants to implement measures offsetting $CO_2$ emissions (EEC Brief, p. 18). The Company stated that subsequent to EEC, the Siting Council stated in Enron that it would "require future applicants of proposed generating facilities, regardless of fuel type, to comprehensively address $CO_2$ emissions, as well as the costs and impacts of possible remedial measures" (id.).

76/ The Company asserted that the Siting Council established precedent in Enron by accepting Enron's proposal to contribute $5,000 to MASS ReLeaf (EEC Brief, pp. 18-19). EEC noted that its $CO_2$ emissions would be approximately six times greater than Enron's $CO_2$ emissions, and that, therefore, a one-time contribution to MASS ReLeaf of $30,000 would be directly proportional to Enron's contribution (id., pp. 18-19).

is that there will be a significant reduction in $CO_2$ emissions from existing electric generating facilities when the proposed facility is in operation (Exh. HO-65A, TA II, p. 2; EEC Brief, pp. 19-20).[77]

The Company further asserted that it would not be appropriate to increase the cost commitment to $CO_2$ mitigation based on its analysis of alternative approaches to attain $CO_2$ offsets (EEC Brief, pp. 20-24). The Company stated that its analysis demonstrated that the cost of increasing its $CO_2$ mitigation, under any of the alternative $CO_2$ mitigation approaches, would have an adverse impact on the financial viability of the proposed facility (Exh. HO-65A, TA II, p. 3).[78]

In addition to cost considerations, the Company stated that the implementation of alternative $CO_2$ emissions offset

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77/ The Company stated that its analysis of the projected NEPOOL dispatch of electric generating facilities when the proposed facility is in operation demonstrated that the overall reduction in $CO_2$ emissions from the facilities that would be displaced by the proposed facility would equal 74 percent of facility emissions (Exhs. HO-65A, TA II, exh. B, AG-165). The Company estimated that, assuming $CO_2$ emissions of approximately 2,489,000 tpy from the proposed facility, the net overall emissions after displacement of approximately 1,833,000 tpy, would be approximately 656,000 tpy (id.).

78/ The Company submitted a pro forma which included the increased capital cost of achieving ten percent $CO_2$ emissions offsets under a CFC approach (Exh. HO-RR-100D). The pro forma indicated that debt service coverage ratios were in the range considered by the Company to be acceptable to a lending institution (id., Exh. HO-E-147). In addition, the pro forma indicated that the impact to return on equity would be small (Exhs. AG-67, Att. A, HO-RR-100D). With regard to a five percent offset requirement under a CFC approach, Mr. Croyle stated that although the proposed facility would likely go forward with such a requirement, the proposed facility has already reached its limit in terms of financial reasonableness due to the incorporation of extensive environmental mitigation (Tr. 19, pp. 138-140). Mr. Croyle stated that he could not specify the point at which additional $CO_2$ mitigation would render the proposed facility financially nonviable (id., pp. 143-144).

approaches would not be feasible and that it is uncertain whether resulting $CO_2$ emissions offsets would be effective and incremental (id., exh. A). With regard to concerns specific to each of the alternative $CO_2$ emissions offset approaches, the Company noted that: (1) there are a limited number of additional reforestation projects available that could be managed to produce effective offsets; (2) there are a limited number of organizations with experience in forest preservation; (3) the relatively low $CO_2$ emission rate of newer automobiles would require a large volume of traffic to be removed to achieve a significant emissions reduction and programs already exist to encourage the reduction of vehicular traffic; (4) efforts to destroy CFCs would be constrained by recent federal requirements limiting CFC emissions and production; and (5) significant $CO_2$ emissions would be a potential by-product of a methane approach (id.).[79]

The Company asserted that an increase in its financial commitment to $CO_2$ mitigation also is not warranted in light of the Company's overall commitment to mitigate the environmental impacts of the proposed facility (Exh. HO-E-149). The Company stated that it has incorporated significant environmental mitigation measures into the proposed facility that exceed the requirements of environmental regulations and that its overall environmental mitigation achieves the proper balance among environmental impacts and between environmental impacts and costs (id.).[80, 81]

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79/ Although the Company expressed concerns regarding the effectiveness of a CFC approach, the Company did indicate that it would be willing to commit its proposed contribution to MASS ReLeaf to a CFC approach if policy-making agencies determined such a strategy should be implemented (Tr. 19, p. 136).

80/ The Company stated that where environmental impacts are subject to regulatory standards, it has been able to assess the cost impact of achieving compliance with such standards and then determine the additional cost impact of mitigation that

### iii. Arguments of the Intervenors

The Attorney General argued that EEC has failed to minimize the $CO_2$ emissions of the proposed facility (Attorney General Brief, pp. 20-35). The Attorney General stated that, in Enron, the Siting Council has already established a requirement that proponents of new generating facilities address $CO_2$ emissions (id., p. 23). The Attorney General argued the Siting Council should now require that proponents of new generating facilities commit to meaningful programs to mitigate $CO_2$ emissions of their facilities (id.).[82]

The Attorney General asserted that, in order to be considered meaningful, a $CO_2$ mitigation strategy must: (1) lead to a real reduction in $CO_2$ emissions;[83] (2) be commensurate with the relative amount of $CO_2$ emitted by the proposed facility;[84] and (3) be significant in comparison to the total

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would go beyond requirements (Exh. HO-E-149). However, with regard to mitigation of $CO_2$ emissions, the Company stated that, in the absence of regulatory control standards and objective measures of $CO_2$ offset expenditures, no cost/benefit analysis is possible to justify additional $CO_2$ offset costs (id.; EEC Brief, pp. 25-26).

81/ The Company also discussed the impacts of increased costs on its power purchase price (Exh. HO-65D).

82/ The Attorney General stated that it is appropriate to regulate the electricity industry as it is a major generator of $CO_2$ (Attorney General Brief, p. 23).

83/ The Attorney General defined a real reduction in $CO_2$ emissions as one that would have not occurred without the implementation of the specific $CO_2$ mitigation program (Attorney General Brief, p. 27).

84/ The Attorney General noted that of the fossil fuel-fired power plants, natural gas plants have the lowest $CO_2$ emissions (Attorney General Brief, p. 27). The Attorney General stated that, therefore, the emission levels of gas-fired plants should serve as a basis to measure whether mitigation strategies proposed by developers of coal and oil-fired facilities are meaningful (id.).

project costs and revenues (id., p. 27).[85] The Attorney General further asserted that the $CO_2$ mitigation contribution proposed by Enron should not be considered a benchmark for evaluating other mitigation strategies (id., p. 28).

The Attorney General argued that EEC's $CO_2$ mitigation proposal is not meaningful in that it would merely replace trees lost to construction and would not mitigate the $CO_2$ emissions of the facility (id., pp. 30-31). In addition, the Attorney General argued that even with the Company's proposed $CO_2$ mitigation, the $CO_2$ emissions from the proposed facility will substantially exceed the emissions of a gas-fired plant, and that the amount of the proposed contribution to MASS ReLeaf is minuscule in comparison to the $650 million capital cost of the proposed facility (id., p. 33).[86]

The Attorney General further maintained that increased expenditures for $CO_2$ mitigation would not affect the viability or profitability of the proposed facility (id., pp. 33-34). In support, the Attorney General stated that the Company itself suggested that although a $3 million expenditure for five percent $CO_2$ mitigation would push "the envelope of reasonableness," an expenditure of this magnitude would not affect the financial viability of the proposed facility (id., p. 33). The Attorney General further stated that the substantial contingency amounts included in the Company's pro formas could be utilized to fund

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85/ The Attorney General argued that if a Company's proposed contribution to a $CO_2$ emission offset strategy is minuscule compared to total project costs and revenues and could be increased without affecting the financial viability of a proposed facility, such an offset strategy would not be considered to be meaningful (Attorney General Brief, p. 27).

86/ The Attorney General also argued that the Company's proposal is not meaningful when compared to existing cost-effective $CO_2$ mitigation strategies such as the Guatemalan reforestation project sponsored in part by AES (Attorney General Brief, p. 34).

increased $CO_2$ mitigation, without affecting the viability or profitability of the proposed facility (id., pp. 33-34).

The Attorney General recommended that the Siting Council deny the Company's application to construct the proposed facility because the Company has not proposed meaningful mitigation of $CO_2$ emissions (id., pp. 35-36). In the alternative, the Attorney General recommended that the Siting Council require offsets for the full amount of $CO_2$ emissions that are above the level of emissions of a comparable gas-fired generating facility (id., p. 35).

NO-COAL argued that EEC's $CO_2$ emissions offset proposal would not result in the offset of any $CO_2$ emissions from the proposed facility (NO-COAL Brief, pp. III-1, IV-3). NO-COAL stated that, taking into account inflation in the price of trees over the 40-year period of the Company's contribution to MASS ReLeaf and the number of trees that will be cleared in order to construct the facility, there will be a net loss in trees, and thus, a net loss in carbon absorption (id., pp. III-1 to III-6).

iv. Analysis

(A) Compliance with Condition

In response to the $CO_2$ condition set forth in EEC, the Company provided cost and environmental impact information for its proposed approach -- a contribution to MASS ReLeaf -- and five alternative approaches. To allow comparison of a range of offset approaches and levels, EEC estimated (1) the relative offset levels of the proposed and alternative approaches assuming an identified cost commitment, specifically the proposed $1.2 million commitment, and (2) the relative costs of the proposed and alternative approaches assuming four different offset levels exceeding the 0.4 percent offset proposed by the Company, specifically five, ten, 20 and 100 percent offsets. In addition, EEC provided available information on experience with a specific mitigation effort under one alternative approach --

reforestation -- sponsored in part by developers of another coal-fired generating project, the AES project in Connecticut. Finally, to allow assessment of the possible impact of $CO_2$ mitigation costs on the viability of the facility, the Company provided a pro forma analysis of the financial effect of a \$6.2 million cost commitment, which is more than five times the proposed commitment and reflects the cost of an offset level of ten percent under the most cost-effective alternative, the CFC approach.

The Company thus provided the requested information in a format specified by the Siting Council. This information included a matrix of offset levels and associated costs incorporating a range of $CO_2$ impact levels for the proposed and other possible approaches. EEC also provided a pro forma analysis for at least one $CO_2$ mitigation option that would further minimize $CO_2$ impacts relative to the proposed mitigation plan. In addition, the information on the AES-sponsored reforestation program provided information useful in assessing the potential for using that mitigation approach.

The Siting Council notes that the Company qualified the results of its analysis by asserting that the feasibility and effectiveness of some of the alternative approaches are uncertain. For example, although its analysis showed cost-effectiveness levels for the CFC approach that are more than three times those of the next most cost-effective approach and more than five times those of the proposed approach, the Company rejected the CFC approach based on uncertainties posed by recent federal restrictions concerning CFCs. Similarly, EEC indicated that the approaches of reforestation and forest preservation would each be approximately 67 percent more cost-effective than the proposed approach, but rejected these approaches based on the Company's belief that there may be limited implementation opportunities.

The Siting Council also notes that the information provided on the AES-sponsored reforestation program demonstrates the potential to achieve greater and more cost-effective mitigation -- 100 percent offset of facility emissions in AES's case -- by working with public, non-profit or other organizations having an interest in such programs. Although the Company cited possible limitations to this approach, it did not describe any efforts it undertook to identify or pursue possible similar opportunities for combining available resources of interested organizations so as to maximize $CO_2$ mitigation. Similarly, although EEC rejected generic approaches with identified cost-effectiveness advantages, as described above, a more detailed investigation of implementation prospects would have allowed EEC to more fully justify its rejection of such approaches.

Nevertheless, on balance, the Company provided a systematic analysis, including consideration of costs and impact on the viability of the facility, for a range of $CO_2$ mitigation approaches and mitigation levels. Accordingly, based on the foregoing, the Siting Council finds that the Company has adequately complied with the condition to provide its plan for attaining $CO_2$ emissions offsets through participation in MASS ReLeaf or other methods and a comprehensive analysis of the environmental and economic impacts of attaining a range of $CO_2$ emission offsets.

Finally, the Siting Council reaffirms the requirement first stated in Enron, that all applicants of proposed facilities that emit $CO_2$ comprehensively address the mitigation of $CO_2$. In future cases, the Siting Council will require petitioners to present alternative $CO_2$ mitigation plans, including likely arrangements for ensuring implementation and verification of estimated results, in order to demonstrate that all cost-effective approaches have been adequately considered and evaluated.

(B) Mitigation of $CO_2$ Emissions

In EEC, the Siting Council acknowledged that $CO_2$ mitigation had not been required as part of previous generating facility reviews (22 DOMSC at 359-361). However, the Siting Council concluded that $CO_2$ emissions from the proposed facility would be significant, noting that they would be two to three times those of a comparably-sized combined-cycle gas-fired plant. Id.

As noted above, in a review subsequent to EEC, the Siting Council directed all future applicants of proposed generating facilities to comprehensively address $CO_2$ emissions, as well as the costs and impacts of remedial measures (see n.75, above). Enron, 23 DOMSC at 196. While the Siting Council accepted a specific $CO_2$ mitigation cost commitment in that review, no guideline or standard for determining the adequacy of $CO_2$ mitigation impacts was set forth. Further, the Siting Council has not established, as part of any other review to date, any specific guidelines or standards for determining the levels of $CO_2$ mitigation that may be required to establish that $CO_2$ emission impacts have been adequately minimized for particular facilities or types of facilities.

In addition, as noted by EEC, $CO_2$ emissions are not currently regulated under state or federal environmental programs. Although $CO_2$ emissions have been included as a category of externality costs in the Department of Public Utilities' Integrated Resource Management regulations (220 CMR 10.00 et seq.), there is little guidance in state policy to assist petitioners in developing $CO_2$ mitigation plans for purposes of Siting Council review.

Here, the parties to this proceeding have presented extensive arguments concerning the level of $CO_2$ mitigation that the Siting Council should require. To fully consider these arguments, the Siting Council first must address the basis for a determination of the level of $CO_2$ mitigation that constitutes adequate minimization of $CO_2$ emission impacts in generating facility cases. The Siting Council then addresses whether EEC's proposed $CO_2$ mitigation plan or an alternative mitigation plan adequately minimizes $CO_2$ emission impacts.

Both the Company and the Attorney General presented arguments on the parameters that should serve as the basis for setting $CO_2$ mitigation levels. The Company asserted that applicants' cost commitments to $CO_2$ mitigation should be proportional to the total $CO_2$ emissions of proposed facilities, specifically asserting that the cost-to-emission ratio accepted by the Siting Council in Enron should apply to the proposed facility. The Attorney General maintained that the quantity of $CO_2$ offsets provided by applicants should be based on the relationship between the $CO_2$ emissions of proposed facilities and those of a comparably sized gas-fired facility, specifically asserting that the applicant should offset all of the difference.

We agree with the Company that the quantity of $CO_2$ emissions from proposed facilities should be an important factor in setting the appropriate level of $CO_2$ mitigation. However, in order to encourage mitigation plans that provide maximum mitigation consistent with minimizing cost, the appropriate level of $CO_2$ mitigation should be evaluated 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. Therefore, we do not accept the Company's argument that a cost-to-emission ratio, taken alone, is the appropriate basis for determining the adequacy of $CO_2$ mitigation plans.

Further, we recognize that the Attorney General's position, that an applicant's $CO_2$ mitigation level should be based on the increment of facility $CO_2$ emission levels above those of alternative facilities, also intuitively makes some sense. However, the Siting Council has some concerns with both the general applicability of the Attorney General's approach as a generic standard, and the Attorney General's specific recommendation that 100 percent of a proposed facility's $CO_2$ emissions above those of a comparatively sized gas-fired facility should be offset.

On a general level, in order to evaluate the impact of a proposed facility's $CO_2$ emissions, it is necessary to relate the facility's $CO_2$ emissions to net changes in regional or national emissions. Therefore, some clarification of the purpose of a proposed facility in meeting energy needs is required, i.e., would the proposed facility displace existing power generating facilities or would the proposed facility be constructed to meet load growth? To the extent that a proposed facility displaces existing power generation facilities, there indeed may be a negative impact on regional or national levels of $CO_2$ emissions corresponding to any excess of the proposed facility's emissions above those of the displaced generation. 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. 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 more closely reflect the total $CO_2$ emissions from the proposed facility. Thus, while comparison of a proposed facility's $CO_2$ emissions to those of alternative generation is relevant, $CO_2$ emissions from any new facility, including a gas-fired facility, can increase regional/national $CO_2$ emission levels and warrant some level of mitigation.

Therefore, with regard to the Attorney General's specific recommendation for determining the extent to which a proposed facility's emissions exceed those of alternative generation, the Siting Council does not agree that a gas-fired facility, in particular, should be used as the basis for this comparison.[87] Rather, we note that a mix of technologies, such as that represented in the Company's generation backout analysis, provides a more relevant basis for establishing such a $CO_2$ emission increment. Here, based on the Company's backout analysis, the $CO_2$ emission increment for the proposed facility is 26 percent (see n.77, above) of its total $CO_2$ emissions -- less than half the $CO_2$ emission increment resulting from a comparison of the proposed facility with a gas-fired facility.

The Siting Council also does not agree with the Attorney General's position that EEC should be required to provide offsets for the full amount of the proposed facility's $CO_2$ emission increment above the emissions of alternative generation. While such an offset level may be useful for ensuring no increase in regional/national $CO_2$ emissions assuming full displacement of the alternative generation, it does not take into account possible impacts on facility cost and viability. Higher costs could directly or indirectly affect ratepayers and, to the extent a facility is rendered non-viable, important benefits of the project, such as regional fuel diversity, could be lost. Further, a higher cost commitment for $CO_2$ mitigation could affect the ability to mitigate other environmental impacts of equal or greater concern. Therefore, the appropriate offset level cannot automatically be assumed to be the full amount of the $CO_2$ emission increment, but may instead be an intermediate level between zero and the full amount of the $CO_2$ emission increment, based on a balancing of $CO_2$ reduction interests against cost and

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87/ To the extent that the Attorney General's argument, that a comparison to a gas-fired facility is appropriate, is based on the fact that a new gas-fired facility would have the lowest $CO_2$ emissions of any fossil fuel-fired generating facility, the Siting Council cannot support this argument. To adopt such a position would ignore the $CO_2$ emissions impacts of gas-fired facilities. The Siting Council must ensure that the environmental impacts of a facility of any fuel or technology are minimized relative to the costs of such facilities.

viability considerations, other environmental mitigation needs, and identifiable facility benefits. Thus, a case-by-case approach is necessary to determine the appropriate level of $CO_2$ mitigation based on such factors.

In future cases, therefore, a variety of relevant project factors -- for example, facility cost, facility $CO_2$ emissions, and any increment of such emissions exceeding the emissions of backed out capacity -- may well be used to determine the appropriate level of $CO_2$ mitigation for proposed facilities. In determining the appropriate mitigation level based on particular factors, the Siting Council will consider the balance between the interest of $CO_2$ mitigation and other interests including cost, viability, other environmental mitigation, and any facility benefits such as supply diversity.

Here, EEC's proposed $1.2 million contribution to MASS ReLeaf over 40 years is a commitment well above Enron's commitment -- a step appropriate for this project. However, given that the present value of the proposed contribution is well under the nominal dollar value, a more up-front payment schedule extending over the first three-to-five years of operation would appear to be more appropriate. In addition, more up-front payments would help ensure that the $CO_2$ offsets provided by the carbon uptake of planted trees would be more fully available during the early years of operation of the proposed facility.

With regard to the relative merits of the proposed $CO_2$ mitigation approach and alternative approaches, the Siting Council recognizes that the planting of urban shade trees through participation in MASS ReLeaf would provide aesthetic and potential summer comfort and thermal load reduction benefits for Massachusetts communities, as well as the identified $CO_2$ mitigation benefits. In addition, participation in MASS ReLeaf is easily implemented, while the various alternative approaches for providing $CO_2$ mitigation involve possible implementation complexities.

However, the record establishes that the approach of reforestation would be 67 percent more cost-effective in mitigating $CO_2$ emissions than EEC's proposed participation in MASS ReLeaf. The record also includes information regarding AES's participation in an international reforestation program, including an overall financial commitment by AES of $2 million. The Siting Council notes that organizations such as Global Releaf are available to facilitate participation in reforestation programs. Therefore, EEC's proposed $CO_2$ compliance would be enhanced if it included a reforestation program element.

With regard to the overall level of $CO_2$ mitigation, the record shows that EEC proposes to offset only small fractions of both its total $CO_2$ emissions and the increment of such emissions above backed out generation.[88] Further, in developing its $CO_2$ mitigation plan, EEC failed to consider the estimated loss of 15,000 trees as part of clearing the proposed site. Thus, it is reasonable to consider whether an increase in EEC's proposed level of $CO_2$ mitigation would be consistent with minimizing cost for purposes of this review. The Siting Council notes that the $2 million contribution by AES to mitigate $CO_2$ emissions from its coal-fired facility is larger than EEC's proposed cost

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88/ As set forth above, the Siting Council may in future generating facility cases balance $CO_2$ reduction interests with considerations of cost, viability, other environmental mitigation, and any facility benefits in order to determine an appropriate $CO_2$ offset level in relation to a proposed facility's total or incremental $CO_2$ emissions. Here, although EEC assessed the financial impact of an alternative $CO_2$ offset and expenditure level which is several times the level it has proposed, the record is not clear as to whether such a level of $CO_2$ mitigation would adversely affect facility viability. Thus, in EEC's case, a comprehensive balancing of $CO_2$ reduction interests with consideration of cost, viability and facility benefits could very well have resulted in selection of a higher offset level than that proposed by EEC, i.e., a more intermediate point between providing no offsets and providing offsets for the full amount of the $CO_2$ emission increment based on the Company's backout analysis.

commitment. Further, EEC has indicated that a cost commitment of up to \$3 million for $CO_2$ mitigation would not jeopardize the viability of the proposed facility. Therefore, it would be consistent with minimizing cost for EEC to at least match the \$2 million level of financial commitment provided by AES.

Accordingly, in order to provide an appropriate overall financial commitment to be made to $CO_2$ mitigation for purposes of this review, EEC should go beyond its proposed \$1.2 million contribution to MASS ReLeaf by also making a contribution through a credible organization or group of organizations to a reforestation program, local, national, or international, in an amount that will result in a total $CO_2$ mitigation expenditure level for the proposed project of \$2 million in present value terms.

The Siting Council finds, therefore, that a $CO_2$ mitigation plan that commits EEC to contribute a total of \$2 million in present value terms, including as significant shares (1) a contribution to MASS ReLeaf, and (2) a contribution through a credible organization or group of organizations to a reforestation program, local, national, or international, would be consistent with an adequate minimization of $CO_2$ emission impacts from the proposed facility, consistent with the minimization of cost, provided that the above contributions are fully paid within five years of commencement of operation of the proposed facility.

#### v. Conclusions on $CO_2$ Emissions

The Siting Council has found that the Company has adequately complied with the condition to provide its plan for attaining $CO_2$ mitigation offsets through participation in MASS ReLeaf or other methods and a comprehensive analysis of the environmental and economic impacts of attaining a range of $CO_2$ emission offsets.

In addition, the Siting Council has found that a $CO_2$ mitigation plan that commits EEC to contribute a total of $2 million in present value terms, including as significant shares (1) a contribution to MASS ReLeaf, and (2) a contribution through a credible organization or group of organizations to a reforestation program, local, national, or international, would be consistent with an adequate minimization of $CO_2$ emission impacts from the proposed facility, consistent with the minimization of cost, provided that the above contributions are fully paid within five years of start up of the proposed facility.

### c. Conclusions on Air Quality

In EEC, the Siting Council found that, upon compliance with the orders relating to NOx and volatile organic compounds ("VOCs"), the air pollutants from the proposed facility, other than $SO_2$ and $CO_2$ are adequately minimized (22 DOMSC at 368). Here, the Siting Council has found that the Company has provided a comprehensive analysis of the availability, environmental impact and economic impact of lower sulfur coal. The Siting Council has also found that if EEC adopts one or more of the above discussed methods for mitigating $SO_2$ emissions, the $SO_2$ emissions from the proposed facility would be adequately minimized, consistent with minimization of cost.

In addition, the Siting Council has found that the Company has provided its plan for attaining $CO_2$ emissions offsets through participation in MASS ReLeaf or other methods and a comprehensive analysis of the environmental and economic impacts of attaining a range of $CO_2$ emission offsets. The Siting Council has also found that if the Company contributes a total of $2 million in present value terms, including as significant shares (1) a contribution to MASS ReLeaf, and (2) a contribution through a credible organization or group of organizations to a reforestation program, local, national, or international, provided that the above contributions are fully paid within five years of commencement of operation of the proposed facility, that the proposed facility's $CO_2$ emissions will be adequately minimized.

Accordingly, the Siting Council finds that the operation of the proposed facility at the proposed site, subject to the directives contained herein, and based on compliance with the orders in EEC, would have an acceptable impact on air quality.

### 3. Conclusions on the Environmental Analysis of the Proposed Facilities

In EEC, the Siting Council found that, subject to the orders contained therein, the environmental impacts of the proposed facility on: (1) water resources; (2) water supply and wastewater; (3) land use; (4) transportation; and (5) safety would be acceptable, and that visual and solid waste impacts would also be acceptable (22 DOMSC at 310-313).

Here, with regard to air quality impacts, the Siting Council has found that the operation of the proposed facility at the proposed site, subject to the directives contained herein, and based on compliance with the orders in EEC, would have an acceptable impact on air quality.

With regard to noise, the Siting Council has found that the operation of the proposed facility would have an acceptable impact on community noise levels.

Accordingly, the Siting Council finds that the construction and operation of the proposed facility at the proposed site, subject to the directives contained herein, and based on compliance with the orders in EEC, would have acceptable environmental impacts.

## C. Cost Analysis of the Proposed Facilities

As noted in EEC, the Siting Council must determine whether proposed facilities are consistent with ensuring a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost (22 DOMSC at 327). Therefore, the Siting Council evaluates proposed facilities to determine whether the cost estimates associated with construction are (1) realistic for a facility of the size and the design of the proposed facility, and (2) minimized consistent with the mitigation of environmental impacts. Id.

In EEC, the Siting Council found that the Company had established that the cost estimates associated with the proposed facility were realistic for a facility of the size and design of the proposed project (22 DOMSC at 331).[89] However, the Siting Council determined that the Company failed to present a comprehensive analysis of the costs associated with incorporating different control options, including its proposed control options, relative to $SO_2$ and $CO_2$ emissions and noise impacts. Id. The Siting Council, therefore, made no finding as to whether EEC had established that the cost estimates of the proposed facility had been minimized consistent with the mitigation of environmental impacts. Id. at 414.

The Siting Council further stated that it would be able to determine whether the cost estimates associated with the proposed facilities are minimized consistent with the mitigation of environmental impacts if the Company submitted the information regarding control technologies for $SO_2$ and $CO_2$ emissions and noise specified in the relevant conditions set forth in EEC (22 DOMSC at 359, 360). In this section, the Siting Council reviews

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89/ EEC indicated that capital cost estimates of the proposed facility had risen since the Siting Council's decision in EEC, but stated that these increased costs were not unreasonable given the passage of time and further development of the entire project (Tr. 21, pp. 6-9). The Company further indicated that these cost increases would not affect the viability or financeability of the proposed project (id.). The Siting Council notes that these cost increases do not affect our finding in EEC that the cost estimates associated with the proposed facility were realistic for a facility of the size and design of the proposed project.

the incremental cost estimates associated with the minimization of $SO_2$ and $CO_2$ emissions and noise impacts to determine whether the cost estimates associated with the proposed facilities are minimized consistent with the mitigation of environmental impacts.

EEC asserted that the additional mitigation strategies it had proposed for $CO_2$, $SO_2$ and noise impacts were the most cost-effective approaches possible and would not adversely affect the viability or competitiveness of the proposed facility (Exh. HO-65A, pp. 1-2; EEC Brief, p. 39). With respect to noise impacts, the Siting Council has found that EEC's proposed noise mitigation strategy, with an incremental cost of $230,000, would minimize noise impacts, consistent with minimizing cost (see Section II.B.1.c, above). However, with regard to $CO_2$ and $SO_2$ impacts, the Siting Council has found that the emissions from the proposed facility would be adequately minimized, consistent with minimizing cost, with mitigation strategies which vary from the mitigation proposed by the Company (see Sections II.B.2.a.iv and II.B.2.b.v, above).

With respect to $SO_2$, the record indicates that $SO_2$ emissions can be minimized, consistent with the minimization of cost, in several ways. As the Company has indicated, facility $SO_2$ emissions can be reduced ten percent below the proposed level of 0.25 lb/MMBtu. This reduction can be achieved through the use of coals with a sulfur content below 1.8 percent, or through the optimization of facility design and operation. Either method will achieve an emission rate of 0.225 lb/MMBtu in a cost-effective manner. In addition, the Company has demonstrated that through an offset program, $SO_2$ emissions from other generating facilities can be reduced at levels significantly beyond those achievable at the proposed facility at a cost less than, or equal to, the costs of mitigation methods at the proposed facility. As such, the Company has shown that through the use of one or more of these methods, $SO_2$ emissions form the facility would be minimized consistent with the minimization of costs.

Further, with respect to $CO_2$, the record indicates that $CO_2$ emissions also can be minimized, consistent with the minimization of cost, in several ways. Although the Company has shown that several of these methods have potential constraints on their utilization, contributions to tree-planting organizations and reforestation efforts remain viable alternatives. The record indicates that such contributions to the extent of a minimum of $2 million over the first five years of the proposed facility's operation would minimize the impacts of $CO_2$ emissions consistent with the minimization of costs.

Accordingly, the Siting Council finds that the cost estimates associated with the proposed facility are minimized consistent with the mitigation of environmental impacts.

D. Conclusions on the Proposed Facilities

The Siting Council has found that the construction and operation of the proposed facility at the proposed site, subject to the directives contained herein and based on compliance with the orders in EEC, will have acceptable environmental impacts.

The Siting Council has also found that the cost estimates associated with the proposed facility are minimized consistent with the mitigation of environmental impacts.

Accordingly, the Siting Council finds that the construction and operation of the proposed facilities at the proposed site is acceptable in terms of cost and in terms of environmental impacts, subject to the directives contained herein, and based on compliance with the orders contained in EEC.

## III. DECISION

In EEC, the Siting Council found that upon compliance with the six conditions set forth therein, the construction of the proposed generating facility and ancillary facilities is consistent with providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost (22 DOMSC at 415).

Here, the Siting Council has found that EEC has complied with the three environmental conditions set forth in Section III.E.11 of EEC (Id. at 410-413).

The Siting Council again notes that the Company must still submit its compliance filing to address those conditions set forth in Section II.C.4 of EEC relative to the viability of the proposed project (Id. at 312-313).

Robert P. Rasmussen

Robert P. Rasmussen
Hearing Officer

Dated this 30th day of July, 1992

APPROVED by a majority of the Energy Facilities Siting Council at its meeting of July 30, 1992 by the members and designees present and voting. Voting for approval of the Tentative Decision as amended: Gloria C. Larson (Secretary of Consumer Affairs and Business Regulation); Brandt Sakakeeny (for Stephen Tocco, Secretary of Economic Affairs); Stephen Remen (Commissioner of Energy Resources); and Joseph Faherty (Public Labor Member). Voting against approval of the Tentative Decision as amended: Mindy Lubber (Public Environmental Member).

Gloria C. Larson

Gloria C. Larson
Chairperson

Dated this 30th day of July, 1992

TABLE 1
Eastern Energy Corporation

**AVERAGE ADDITIONAL COSTS FOR LOWER SULFUR COALS**

| Coal Region | Incremental Total Cost $1,000,000/yr | Emission Reduction $/Ton $SO_2$ |
|---|---|---|
| Pennsylvania/Conrail-Standard | ---- | ---- |
| Pennsylvania/Conrail-Other | $2.5 | $13,835 |
| West Virginia/Conrail | $8.7 | $13,617 |
| West Virginia, Maryland/CSX | $9.9 | $12,972 |
| Kentucky/CSX | $11.2 | $16,525 |
| Kentucky, West Virginia, Virginia/N&W | $5.3 | $6,314 |

Source: Exh. HO-65A, EnviroFuels Report, p. 15

Appeal as to matters of law from any final decision, order or ruling of the Siting Council 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 Council be modified or set aside in whole or in part.

Such petition for appeal shall be filed with the Siting Council within twenty days after the date of service of the decision, order or ruling of the Siting Council, or within such further time as the Siting Council 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).