Decision and Orders

Massachusetts Energy Facilities Siting Council

VOLUME 19

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PUBLICATION #16,356-474-100-6-90-C.Rc.
APPROVED BY: RIC MURPHY, PURCHASING AGENT

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

Occasional Supplement of Boston Edison Company to its Long-Range Forecast of Electrical Power Needs and Requirements, 1988 - 2011, for a Transmission Line and Substation, pursuant to General Laws Chapter 164, Sections 69H, 69I and 69J; petition of the Massachusetts Water Resources Authority to construct, maintain and operate an underground transmission line from K Street Substation in South Boston to Deer Island in the City of Boston, pursuant to General Laws Chapter 164, Sections 69H, 69I and 69J.

EFSC 89-12A

FINAL DECISION

Stephen Klionsky
Hearing Officer
September 27, 1989

On the Decision:

Robert M. Graham

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The Energy Facilities Siting Council hereby CONDITIONALLY APPROVES the petition of the Boston Edison Company and the Massachusetts Water Resources Authority to construct a single-circuit, 4.15-mile, underground/submarine, 115 kilovolt electric transmission line from its K Street substation in South Boston to Deer Island along the proposed route described herein.

I. INTRODUCTION

A. Summary of the Proposed Project and Facilities

The Boston Edison Company ("BECo" or the "Company") and the Massachusetts Water Resources Authority ("MWRA") (referred to collectively herein as the "Petitioners") have petitioned the Energy Facilities Siting Council ("Siting Council") for approval to construct, maintain and operate a 4.15-mile, 115 kilovolt ("kV"), underground and submarine line to connect BECo's K Street substation on South Boston to a proposed new temporary substation at Deer Island.[1] The electric power transported over the proposed line would be used to support the construction of the MWRA's major new primary and secondary wastewater treatment facilities at Deer Island and would serve as a source of long-term operating power for these facilities. The proposed transmission line would consist of three separate cables, each containing a single conductor, and would be capable of carrying 70 megawatts ("MW") (Exh. BE-1, p. 2-1).

BECo is an investor-owned electric utility engaged in the generation, purchase, transmission, distribution, bulk power sale and retail sale of electricity. In 1986, Boston Edison provided retail electric service to 40 cities and towns in the greater Boston metropolitan area and wholesale service

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[1] This filing was originally submitted on February 1, 1989 solely by BECo. On March 29, 1989, the MWRA was added as a copetitioner.

The proposed transmission line would later be connected to a permanent substation to be constucted on Deer Island at a site immediately adjacent to the site of the temporary substation.

to 19 customers, primarily municipal light boards. Boston Edison Company, 18 DOMSC 201, 205 (1989) ("1989 BECo Decision"). BECo had total electricity sales in 1986 of 11,685 gigawatthours and the Company's retail sales of electricity account for approximately 30 percent of the retail electricity sold in Massachusetts. Peak usage of electricity on the BECo system occurs during the summer months (id.). After reviewing the Company's most recent forecast filing, the Siting Council, on February 16, 1989, approved BECo's demand forecast and supply plan (id.).

The MWRA is a public authority which, on July 1, 1985, among other responsibilities, assumed control of the metropolitan Boston sewage system (Exh. BE-1, App. IV).

B. Procedural History

Following the February 1, 1989 BECo filing and the March 29, 1989 filing amendment, the Siting Council, on April 27, 1989, held a joint public hearing with the Massachusetts Department of Public Utilities ("DPU") in South Boston.[2] No party intervened in this proceeding.[3]

The Siting Council conducted an evidentiary hearing on July 27, 1989. The Petitioners presented three witnesses: Christopher J. Barnett, Technical Manager of the MWRA; Gregory R. Sullivan, Manager of the Distribution and Planning Section in the Electrical Engineering and Station Operations Department of BECo; and Dr. Lillian N. Morgenstern, Principal Environmental

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2/ The Siting Council has entered into a Memorandum of Understanding with the DPU in order to coordinate the review of a proposed energy facility, such as this one, over which both agencies have jurisdiction.

3/ On May 8, 1989, the Massachusetts Bay Transportation Authority ("MBTA") filed a petition to intervene in this proceeding. While the MBTA was subsequently notified of all aspects of this proceeding, it did not participate in any manner and its petition was never ruled upon.

Planner in the Environmental Affairs Department of BECo.

The Hearing Officer moved 161 exhibits into the record, largely composed of the Petitioners' responses to information and record requests. The Petitioners moved 16 exhibits into the record. The Petitioners filed a brief on August 10, 1989.

C. Jurisdiction

The Petitioners' filing is submitted 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 electric companies to obtain Siting Council approval for construction of proposed facilities before a construction permit may be issued by any other state agency.

The Petitioners' proposal to construct a 4.15-mile, 115 kV electric transmission line falls within the second definition of "facility" set forth in G.L. c. 164, sec. 69G. This section grants the Siting Council jurisdiction over any new electric transmission line having a design rating of 69 kV or more which is one mile or greater in length, except reconductoring or rebuilding existing transmission lines at the same voltage.

The construction of the proposed temporary substation falls within the third definition of "facility" set forth in G.L. c. 164, sec. 69G. That section gives the Siting Council jurisdiction over any ancillary structure which is an integral part of the operation of any electric generating unit or transmission line which is a facility. In <u>Commonwealth Electric Company</u>, 17 DOMSC 249, 259-265 (1988) ("1988 ComElectric Decision"), the Siting Council established a two part standard for determining whether a structure is a facility under this third definition. Pursuant to the 1988 ComElectric decision, a structure is a 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. In the instant case, the proposed temporary substation clearly is subordinate to the proposed jurisdictional transmission line and provides no benefit outside of its relationship to this 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 applications in three phases. First, the Siting Council requires applicants to demonstrate that the facilities are needed (see Section II.A, infra). Next, the Siting Council requires the applicant to present project approaches that satisfy the previously identified need and that are superior to alternative project approaches in terms of reliability, cost and environmental impact (see Section II.B, infra). Finally, the Siting Council requires the applicant to show that the proposed site or route for a facility is superior to alternate sites or routes in terms of cost, environmental impacts and reliability of supply (see Section III, infra).

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.[4] 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 the system is found to be inadequate to satisfy projected load and reserve requirements. New England Electric System, 18 DOMSC 383, 393 (1989) ("1989 NEES Decision"); Altresco-Pittsfield, Inc., 17 DOMSC 351, 359-369 (1988) ("Altresco"); Northeast Energy Associates, 16 DOMSC 335, 344-360 (1987) ("NEA"); Cambridge Electric Light Company,

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[4] In this discussion, "additional energy resources" is used generically to mean both energy and capacity additions, including, but not limited to, electric generation facilities, electric transmission lines, energy or capacity associated with power sales agreements, and energy or capacity associated with conservation and load management.

15 DOMSC 187, 211-212 ("1986 CELCo Decision"); Massachusetts Electric Company, 13 DOMSC 119, 137-138 (1985) ("1985 MECo Decision"); 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 is maintained in the event that a reasonably likely contingency occurs. Middleborough Gas and Electric Department, 17 DOMSC 197, 216-219 (1988) ("1988 Middleborough Decision"); Boston Edison Company, 13 DOMSC 63, 70-73 (1985) ("1985 BECo Decision"); Taunton Municipal Lighting Plant, 8 DOMSC 148, 154-155 (1982) ("1982 Taunton Decision"); Commonwealth Electic 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. 1985 MECo Decision, 13 DOMSC at 178-179, 183, 187, 246-247; Boston Gas Company, 11 DOMSC 159, 166-168 (1984).

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 broadly to encompass not only evaluations of specific need within Massachusetts for new energy resources (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. Altresco, 17 DOMSC at 359-365; NEA, 16 DOMSC at 344-354; Massachusetts Electric Company, 15 DOMSC 241, 273, 281 (1986); 1985 MECo 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' electricity 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").

In the instant case, the Siting Council is presented with a proposal to build a jurisdictional electric transmission line and appurtenant structures where the need for the proposed facilities is asserted to be solely due to the requirements of a single, new customer. In cases such as this, in order to establish that additional energy resources are needed on reliability grounds, the Petitioner must demonstrate that the capacity of the existing transmission system available to the customer is inadequate to satisfy the customer's projected load requirements. If appropriate, Petitioners also can establish that additional energy resources are needed on economic efficiency grounds.

2. Need for Additional Energy Resources

a. Background

The Petitioners asserted that there is a recognized need to improve treatment of the sewage flow generated by the communities served by the MWRA, and that the proposed additional energy resources are needed to provide construction power for the planned new wastewater treatment facilities (Exh. BE-1, pp. 1-1 to 1-6). In support of their assertion, the Petitioners provided information on the current state of Boston Harbor and the need for the planned new wastewater treatment facilities on Deer Island. This information is summarized below.

Boston Harbor is approximately 50 square miles in size and the largest seaport in New England (Exh. HO-RR-3, pp. 3-1, 3-15, 3-16). The Harbor supports a variety of recreational and commercial activities, including swimming, recreational boating and fishing, hiking and camping on the Harbor islands, and commercial shellfishing and lobstering (id., pp. 3-1 to 3-20). The Petitioners stated that "the natural resources of Boston Harbor are of considerable aesthetic, economic, social and ecologic value" and that "the visual resources of the Harbor are a tremendous value and a major attraction" (id., pp. 3-1 to 3-17).

The Harbor, however, is beset by serious environmental problems, as summarized by the MWRA in the following statement:

> The features which make Boston Harbor so unique and diverse are defaced by the urban pollution which flows from the sewers and storm drains of the metropolis. Bacterial contamination prevents the harvesting of shellfish from almost half of the Harbor's productive beds and is responsible for beach closings. Sewage and toxic chemicals discharged to the Harbor have altered the populations of marine plants and animals of the Harbor. Bioaccumulation of toxic chemicals in Harbor fish has brought into question the health effects in humans who eat these fish. Floating sewage, oil, grease, and debris impair the visual quality of Boston Harbor and undoubtedly discourages recreation. (Id., p. 3-3).

The MWRA is the agency responsible for the collection and treatment of sewage for approximately 1.9 million people in 43 communities in the Boston metropolitan area (Exh. BE-1, p. 1-1). The MWRA presently operates two sewage treatment facilities, which it contends are antiquated and unable to provide consistent primary treatment of sewage flow generated by those communities (id.). On average, sewage flow exceeds the capacity of the existing wastewater treatment facilities on 52 days per year, resulting in billions of gallons of raw sewage entering the Harbor each year (Tr. 16). Furthermore, according to the Petitioners, the Massachusetts and United States Clean Water Acts both require secondary treatment of sewage but neither of the existing treatment plants provides this level of treatment (Exh. BE-1, p. 1-1; Tr. 11).

The Petitioners stated that a violation of sewage discharge standards led the municipality of Quincy to file a lawsuit against the Metropolitan District Commission (the agency that had responsibility for the metropolitan Boston sewage system prior to the creation of the MWRA) in Massachusetts Superior Court in 1982 (Exh. BE-1, p. 1-1; Tr. 11-12). Three years later, the U.S. Environmental Protection Agency ("EPA") filed a suit against the newly-created MWRA in U.S. District Court, alleging violations of the federal Clean Water Act (id.). In September 1985, the federal court found that the MWRA was violating standards of the federal Clean Water Act and ordered the construction of new primary and secondary treatment facilities (id.). The Petitioners stated that in 1986 the MWRA decided to decommission its existing wastewater treatment facilities and, after detailed consideration of alternative sites, decided to construct the new primary and secondary treatment plants on Deer Island (id.).

In May 1986, the court ordered the MWRA to complete construction of the wastewater treatment facility according to what the Petitioners characterized as an "aggressive schedule," requiring the completion of new primary treatment facilities and a large new outfall tunnel by 1995 and completion of secondary treatment facilities by 1999 (Exh. BE-1, p. 1-1).[5] The court schedule also contains a number of smaller, intermediate milestones and has undergone several modifications. The most recent court schedule, designated Schedule Three, was contained in the May 23, 1989 decision of the U.S. District Court ("Court Order") (Exh. HO-1). See also Section II.A.2.b, infra.

According to BECo and the MWRA, the result of the construction of the new wastewater treatment facilities will be improved water and sediment quality and healthier and more diverse marine life in Boston Harbor (Tr. 177).

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[5] The outfall tunnel will serve as the conduit for treated sewage into the outer harbor. The Petitioners stated that it will be 8.5 miles long and 27 feet in diameter (Exh. BE-1, p. 1-2).

b. Power Requirements

The Petitioners are requesting Siting Council approval for electric transmission facilities to permit construction of the planned wastewater treatment plant (Brief, p. 1). While the Siting Council herein evaluates the need for additional energy resources to meet the MWRA's near-term need for construction power, the Siting Council also recognizes that the Petitioners plan to utilize additional energy resources to provide permanent power for the long-run operation of the wastewater treatment plant and that the Petitioners have taken these long-run power requirements into account in their determination of the appropriate capacity of the proposed facilities (Exh. BE-1, pp. 2-1, 2-2).

The MWRA and BECo stated that construction of the planned Deer Island wastewater treatment facilities will require sufficient power to serve a peak projected load of 15 MW by July 1990 (Exh. BE-1, pp. 1-2, 2-1). This power will be used to drive two large-bore deep rock tunnel boring machines for excavation of the outfall tunnel (7.0 MW required) and a sewage conveyance tunnel connecting Nut Island to Deer Island ("the interisland tunnel") (5.0 MW required) as well as for concrete batching (3.0 MW required) (id.).

According to the Petitioners, the schedule set by the Court Order calls for the start-up of tunneling operations for the outfall tunnel in January 1991 and completion of the tunnel by July 1995 (Tr. 35-36, Exh. HO-1). The MWRA, however, stated that it has some concerns regarding its ability to complete the tunnel within the period established in the schedule and therefore is doing all that it can to secure all permits to enable the commencement of construction of the outfall tunnel in October 1990 or sooner (Tr. 36-37).[6]

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[6] The record is inconsistent with regard to the date when construction power is required. At times the Petitioners cite July 1990 as this date (Exh. BE-1, p. 1), while at other times the Petitioners use mid-1990 (id., p. 1-2), 1990 (id., p. 2-1), or October 1990 (Tr. 36-37). Based on the record, the Siting Council finds that "mid-to-late 1990" is the most acceptable description of the date by which construction power is required.

The Petitioners also stated that construction of the interisland tunnel will begin in late 1990 or early 1991, depending on the date of the contract award and the selected contractor's ability to mobilize, and is expected to be completed in late 1994 (Exhs. BE-1, p. 1-2, HO-1, HO-3). According to BECo and the MWRA, concrete batching is expected to begin in the second quarter of 1990. This batching would operate at less than full capacity and would require the use of expensive diesel generators until additional energy resources are obtained (Tr. 42-43).

The construction power need of 15 MW will exist until late 1995, according to the Petitioners, after which it will fall to approximately 3 MW until 1999, when construction is scheduled to be completed (Exh. BE-1, pp. 1-2, 1-3). In addition to its need for construction power, the MWRA requires incremental power supplies for the operation of the primary and secondary wastewater treatment facilities and related activities (id., pp. 1-3 to 1-6). The Petitioners stated that, from 1991 onward, primary sludge dewatering, basic power and the operation of piers will require a peak load of 4.5 MW (id., p. 1-6, Exh. HO-10).

BECo and the MWRA stated that the electric power requirements of the new primary treatment facilities, which are scheduled to be placed into service in phases from 1993 to 1995, will exceed construction loads (Exh. BE-1, p. 1-4). Beginning in 1993 and 1994, the MWRA will place into service nine new electric pumps with a peak pumping load of 20.25 MW in the Main Pump Station, and six smaller pumps with a peak load of 1.8 MW in the northern main sewer terminal on Deer Island (id., pp. 1-3 to 1-6). Peak load for the construction and operation of the entire wastewater treatment facility is expected to rise from 10.3 MW in 1988-89 to 40.6 MW by 1993-94, according to the Petitioners (id., p. 1-6). The Petitioners further stated that peak load is expected to increase to 45.2 MW in 1995 to provide basic power for the new primary treatment facility and power for several additional pumps (id., pp. 1-4 to 1-6).

The Petitioners stated that electrical loads will continue to increase from 1995 through 1999, as construction of the four secondary treatment batteries is completed in sequence and these facilities are placed into service (id., p. 1-5). The secondary treatment facility is expected to be completed and in full operation by 1999, at which time peak power demand for the entire Deer Island facility is expected to be approximately 65 MW.

Table 1 presents a summary of average load, essential peak load, peak load and expected shortfall[7] by year for the construction and operation of the planned Deer Island wastewater treatment facilities. As the table indicates, an electric power shortfall of approximately 15.6 MW would exist in 1990 in the absence of new transmission facilities. This shortfall is expected to increase to approximately 20 MW in 1991-92, 39 MW in 1995, and 58 MW in 1999 (id., p. 1-6; Exh. BE-8, pp. 2-2 to 2-4).

For the purposes of this review, the Siting Council accepts the evidence presented by the Petitioners regarding the condition of the Harbor, the state of present sewage treatment facilities and the Court Order as an adequate demonstration of the need for new wastewater treatment facilities. Accordingly, the Siting Council finds that the Petitioners have established that approximately 15 MW are needed by mid-to-late 1990 in order to support construction of the planned wastewater treatment facilities and that in the longer term approximately 58 MW will be required to operate these facilities.

c. Adequacy of the Existing System

BECo and the MWRA stated that power for the existing wastewater treatment facilities on Deer Island is generated on-site at a power plant with an installed capacity of 15.5 MW (Exh. BE-1, p. 3-1). This power plant has virtually no excess

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7/ See Table 1 for a definition of these terms.

capacity available to serve construction loads, according to the Petitioners (id.).

The only existing off-island power source is a recently upgraded 3000 kilovolt-ampere ("kVA") (equivalent to 3 MW) overhead distribution line which links an adjacent facility on Deer Island with MECo's distribution system in Winthrop (id., Tr. 20-21). The Petitioners stated that this distribution line "is clearly insufficient" for the required construction power of 15 MW or the longer-term power requirements for operating the Deer Island facilities (Exh. BE-1, p. 3-1).

The Siting Council finds that the Petitioners have established that the existing electric power system is inadequate to provide the approximately 15 MW needed to support construction of the planned wastewater treatment facilities and the approximately 58 MW required at a later date to operate these facilities.

3. Conclusions on Need

The Siting Council has found that the Petitioners have established that: (1) approximately 15 MW are needed by mid-to-late 1990 in order to support construction of the planned wastewater treatment facilities and in the longer term 58 MW are required to operate these facilities; and (2) the existing electric power system is inadequate to support these power requirements.

Accordingly, the Siting Council finds that additional energy resources are needed on reliability grounds.

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: (1) other methods of generating, manufacturing or storing energy; (2) other sources of electrical power or natural gas; and (3) no additional electrical power or natural gas.[8]

In implementing its statutory mandate, the Siting Council has required a petitioner to show that, on balance, its proposed project is superior to alternative approaches in terms of cost, environmental impact and ability to meet the identified need. Turners Falls Limited Partnership, 18 DOMSC 141, 171-172 (1988) ("Turners Falls"); Braintree Electric Light Department, 18 DOMSC 1, 27 (1988) ("1988 Braintree Decision"); 1988 ComElectric Decision, 17 DOMSC at 279-288; 1988 Middleborough Decision, 17 DOMSC at 219-225; 1986 CELCo Decision, 15 DOMSC at 212-218; 1985 BECo Decision, 13 DOMSC at 67-68, 73-74. The Siting Council also has considered reliability impacts in comparing proposed and alternative project approaches. 1989 NEES Decision, 18 DOMSC at 19.

2. Project Approaches to the Identified Need

In their filing, the Petitioners proposed project approach is to construct a 115 kV electric transmission line from South Boston across Boston Harbor to Deer Island. The Petitioners also considered six alternate approaches to the proposed project: (1) a no action alternative; (2) relying on distribution supply from the Massachusetts Electric Company ("MECo") system in Winthrop; (3) use of distribution supply from MECo's system in Revere; (4) construction of one of two

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[8] G.L. c. 164, sec. 69I, also requires a petitioner to provide a description of "other site locations." See Section III, infra.

low voltage alternatives from BECo's K Street substation in South Boston; (5) construction of a 115 kV transmission line from BECo's system in Chelsea ("BECo northern route alternative"); and (6) on-site generation.

The Petitioner's proposed project approach and the BECo northern route alternative both involve the construction of 115 kV transmission lines that would interconnect with the BECo transmission system. The Petitioner's proposed project approach and the BECo northern route alternative differ from each other primarily in their route and point of origin. The Siting Council therefore considers the BECo northern route alternative to be a facility alternative rather than an alternative project approach. Accordingly, BECo's northern route alternative is considered in the analysis of alternative facilities in Section III, infra.

Each of the project approaches considered by the Petitioners, with the exception of the BECo northern route alternative, is evaluated below by the Siting Council on the basis of whether it meets the identified need for construction power for the planned wastewater treatment facilities on Deer Island. See Section II.A.2, supra.

a. Proposed Project Approach

As their preferred project approach to meeting the identified need, the MWRA and BECo have proposed to construct facilities consisting of: (1) a temporary substation on Deer Island; (2) a 115 kV transmission line connecting the temporary substation on Deer Island with BECo's K Street substation in South Boston; and (3) a permanent substation on Deer Island to replace the temporary substation by 1995 (Exh. BE-1, pp. 2-2, 2-3).[9] The Petitioners also plan to install line terminal equipment and a 115 kV circuit breaker within the K Street

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9/ The Petitioners stated that the temporary substation is required on an interim basis until the permanent substation can be completed because: (1) the (cont.)

substation to link the proposed transmission line with the existing BECo transmission network (id.).

The Petitioners identified a preferred (or proposed) route, designated Route S-1, a variation of the preferred route, designated Route S-1A, and an alternative route, designated Route S-2 (Exh. BE-1, pp. 2-1 to 2-9). These routes are described in detail in Sections III.B.1 and III.B.2, infra. The Petitioners also considered two configurations for the proposed temporary substation (Exh. HO-21). The proposed temporary substation would feature an open air configuration; a second configuration would involve enclosed construction of the substation (id.).

The proposed transmission line would have a capacity of 70 MW and therefore would be capable of providing both construction power (15 MW required) and long-term operating power (58 MW required) for the planned wastewater treatment plant on Deer Island (Exhs. BE-1, p. 2-1; BE-8, pp. 2-2 to 2-8). See Section II.A.2.b, supra.

The date by which power would be available would depend on the route selected. The Petitioners stated that Routes S-1 and S-1A could be completed by July 1990 or earlier, in time to provide power for the startup of major construction activities (Exhs. BE-1, pp. 1-2, 2-1, 8-2; HO-101). BECo and the MWRA indicated that the timeframe for the construction of Route S-2 is similar to Route S-1 except that some additional time may be needed for more extensive regulatory review and for archeological studies of the Fort Independence area (Exh. BE-1, pp. 6-3, 8-2).

The Siting Council finds that the Petitioners have demonstrated that the proposed project approach addresses the identified need for construction power for the planned wastewater treatment facilities on Deer Island.

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[9] (cont.) intended site for the permanent substation will not be available until after construction power is required; and (2) a lead time of two years or more is needed for obtaining switching and bus equipment for the permanent substation (Tr. 140-145).

b. No Action Alternative

The Petitioners considered a "no action alternative" under which no steps would be taken to provide additional electricity supplies to serve Deer Island (Exh. BE-1, p. 3-1). In Section II.A.2.c, supra, the Siting Council found that the existing generation and transmission systems serving Deer Island are inadequate to meet the MWRA's projected load requirements.

Accordingly, the Siting Council finds that the Petitioners have demonstrated that the no action alternative fails to address the identified need for construction power for the planned wastewater treatment facilities on Deer Island.

c. Distribution Supply from Massachusetts Electric System in Winthrop

The MWRA and BECo stated that they initially considered MECo's distribution system in Winthrop as a source of supply to meet the MWRA's requirements for construction power (id.). Preliminary discussions were held with MECo regarding the construction of either an overhead or underground 24 kV distribution line from MECo's Metcalf Square substation in Winthrop to Deer Island via Winthrop city streets (id., pp. 3-3, 3-4). According to the Petitioners, however, this alternative was abandoned when MECo determined that projected construction power needs would exceed the availability of supply from Metcalf Square (id., p. 3-3).

The Siting Council finds that BECo and the MWRA have demonstrated that an alternative involving the construction of a distribution line from MECo's Metcalf Square substation to Deer Island fails to address the identified need for construction power for the planned wastewater treatment facilities on Deer Island.

d. Distribution Supply from Massachusetts Electric System in Revere

The Petitioners stated that they also investigated an alternative transmission option with MECo which would have involved the construction of an underground cable from MECo's Revere substation through Revere and Winthrop to Deer Island ("MECo Revere alternative") (id.). According to the Petitioners, MECo's preliminary design work indicated that the only feasible means of meeting the MWRA's identified construction power requirements from Revere would be a buried cable operating at 24 kV (id., p. 3-3). As a result, a second supply cable would have to be built to provide the MWRA's long-term power needs, making this alternative uneconomical, according to the MWRA and BECo (Brief, p. 14).

In addition, the route of the MECo Revere alternative would follow many of the same streets through Winthrop along which the MWRA plans to install new water and gas mains (Exh. BE-1, p. 14). The MWRA has entered into a Memorandum of Understanding with the Town of Winthrop under which, to avoid further disruption to Winthrop, any new gas or water utilities will be constructed, to the maximum extent possible, in the same right-of-way at the same time (Exh. BE-1, App. II, p. 9). The MWRA also stated that any other utility construction in Winthrop muust be done at the same time in the same single street opening (Exh. BE-1, pp. 3-3, 3-5; Tr. 57-58; Brief, p. 13).

The Petitioners stated that due to the need to wait for the completion of preparatory work and regulatory approvals for other utility lines before the construction of the transmission line along this corridor could commence, and due to other complexities inherent in the MECo Revere alternative, this alternative could not be completed until at least July 1991, 12 months beyond the projected in-service date of the proposed project approach (Tr. 61, Brief, p. 14). They further asserted that the MECo Revere alternative has a significant potential for further delays and cost increases because of possible difficulties in obtaining local and state permits and because of possible restrictions on construction activities (Tr. 59-60). The Petitioners concluded that compliance with the schedule set by the Court Order would be impossible with the MECo Revere alternative (Brief, p. 14).

The Siting Council finds that the Petitioners have demonstrated that the MECo Revere alternative fails to address the identified need for construction power for the planned wastewater treatment facilities on Deer Island.

e. Low Voltage Supply from BECo System in South Boston

The Petitioners stated that they analyzed two alternatives for providing construction power for the planned Deer Island facilities from the K Street substation in South Boston using a lower voltage than the 115 kV capacity of the proposed project approach (Exh. BE-1, pp. 3-5, 3-6). These two alternatives will be referred to herein as "low voltage alternative 1" and "low voltage alternative 2."

Low voltage alternatives 1 and 2 are similar in some respects in that they both would involve: (1) construction of an electric transmission line along one of the proposed routes identified in Section II.B.2.a, supra; (2) the installation of a 115 kV/14 kV or 115 kV/24 kV transformer at the K Street substation in South Boston; and (3) the operation of the transmission line at a distribution voltage of 14 kV or 24 kV prior to the 1995 scheduled start-up of the new primary treatment plant (id., p. 3-5). They differ in that low voltage alternative 1 would utilize a cable rated and operated at a distribution voltage of 14 kV or 24 kV, whereas low voltage alternative 2 would, on an interim basis, utilize a cable with a rated capacity of 115 kV but operate at 14 kV or 24 kV until permanent operating power is required (id.). According to the Petitioners, the capacity of low voltage alternative 1 would be sufficient for construction power only and could not serve adequately as a source of permanent power (id.).

The Petitioners also stated that two circuits (six cables) would be required for low voltage alternative 1 because of limitations on the size of distribution submarine cable and BECo's concerns regarding the high amperage and consequent high power losses associated with providing construction power with a single 14 kV or 24 kV circuit (Exh. HO-RR-5, Tr. 122-126). The MWRA and BECo stated that for two circuits, construction would require either two trenches or a trench twice as wide as that needed for the proposed project approach (Exh. HO-RR-5, Tr. 131). Low voltage alternatives 1 and 2 would involve the same routes and construction methods as the proposed project approach and therefore the timing for these alternatives would be similar to that anticipated for the proposed project approach (Tr. 122).

The Siting Council finds that low voltage alternative 1 and low voltage alternative 2 would each address the identified need for construction power for the planned wastewater treatment facilities on Deer Island.

f. On-Site Generation

In addition to various electric transmission and distribution alternatives, BECo and the MWRA stated that they also considered the early installation of the combustion turbine portion of a possible combined-cycle power plant to be built on Deer Island (Exh. BE-1, pp. 3-7 to 3-8, Brief, p. 15). According to the Petitioners, this option was rejected because selection, procurement, permitting and installation of a combustion turbine by 1990 was not feasible (id.). The Petitioners further asserted that since the gas mains could not be completed in time to provide construction power, the turbine would initially have to burn oil (Exh. BE-1, p. 3-8). However, the Petitioners maintained that state air quality restrictions severely limit oil use at the existing Deer Island facility at present (id.). Also, the cost and reliability of power from the combustion turbine would be inferior to that of a utility transmission line, according to the Petitioners (id.).

Accordingly, the Siting Council finds that the Petitioners have demonstrated that the on-site generation alternative fails to address the identified need for construction power for the planned wastewater treatment facilities on Deer Island.

g. Conclusions on Project Approaches to the Identified Need

The Siting Council has found that the Petitioners have demonstrated that the: (1) proposed project approach; (2) low voltage alternative 1; and (3) low voltage alternative 2 each address the identified need for construction power for the planned wastewater treatment facilities on Deer Island. The Siting Council has also found that the: (1) no action alternative; (2) distribution supply from the MECo system in Winthrop; (3) MECo Revere alternative; and (4) on-site generation each fail to address the need for construction power for the planned wastewater treatment facilities on Deer Island.

3. Reliability, Cost and Environmental Impacts

In Section II.B., *supra*, the Siting Council found that two project approaches address the need for construction power for the planned MWRA facilities on Deer Island. These two approaches are the proposed project and low voltage alternatives 1 and 2. The Siting Council evaluates these two project approaches below on the basis of reliability, cost and environmental impacts.

a. Reliability

The Petitioners stated that there would not be any significant differences in reliability between the proposed project approach, low voltage alternative 1 and low voltage alternative 2 (Tr. 129-130).

The Siting Council finds that the proposed facilities, low voltage alternative 1 and low voltage alternative 2 are comparable with respect to reliability.

b. Cost

The Petitioners provided estimates for the capital and operating costs of the proposed project approach and the two low voltage alternatives for Routes S-1 and S-2 (Exh. HO-RR-5). These estimates are summarized in Tables 2 and 3, infra. The capital costs for the proposed project approach for Routes S-1 and S-2 would be approximately $14.8 million and $17.6 million, respectively, in current (1989) dollars (id., Exhs. HO-24, HO-144).

The Petitioners indicated that the capital costs of low voltage alternative 2 would be similar to those of the proposed project approach (Tr. 125-127). The trenching operations, 115 kV cable, transformer, 14 kV bus and switchgear would be common to both the proposed project approach and low voltage alternative 2 (id.). The only difference in terms of capital costs between these approaches is that low voltage alternative 2 would not require a 115 kV circuit switcher, resulting in an estimated savings of $70,000 to $80,000 relative to the proposed project approach (Tr. 128-129). These savings would to some degree be offset by the additional cost for low voltage alternative 2 of moving the transformer from South Boston to Deer Island once the transmission line needs to be operated at its full 115 kV capacity.

The estimated capital cost for low voltage alternative 1 would be $800,000 to $3.6 million less than the capital cost to build the proposed project approach or low voltage alternative 2, depending on the route and distribution voltage selected (Exh. HO-RR-5). According to the Petitioners, however, these capital cost estimates fail to take into account the fact that low voltage alternative 1 could not adequately serve as a source of permanent power for the operation of the Deer Island facilities, whereas the proposed project approach and low voltage alternative 2 would have sufficient capacity to serve both the construction and permanent power needs of the wastewater treatment plant (id.). The Petitioners asserted that low voltage alternative 1 would have to be replaced by a 115 kV transmission line or be supplemented by additional distribution circuits by 1995 in order to provide the long term power needs of the facilities (id., Exh. BE-1, p. 3-5). If the capital costs of the additional lines required to provide permanent power are included, the proposed project approach and low voltage alternative 2 would then have a capital cost of approximately $6.7 to $10.2 million less than the estimated cost of low voltage alternative 1, according to figures provided by BECo and the MWRA (Exh. HO-RR-5).

While the Siting Council herein evaluates the proposed and alternate project approaches primarily on the basis of their ability to meet the MWRA's near-term need for construction power, the Siting Council, as noted in Section II.A.2.b, supra, also recognizes that these approaches would have long-run benefits and consequences which must be weighed in the process of determining whether the proposed project is needed and results in a minimum impact on the environment at the lowest possible cost.

In the instant case, the Siting Council concludes that the appropriate basis for comparing the capital cost of low voltage alternative 1 with the capital costs of the proposed project approach and low voltage alternative 2 includes the capital cost of an additional circuit to provide permanent power for the Deer Island wastewater treatment facilities. The comparable cost of low voltage alternative 1 with this additional circuit is $21.5 to 27.8 million.

The operating costs of the proposed project approach and the low voltage alternatives are presented in Table 3, infra. The table shows that the operating costs of the proposed and alternative project approaches over the useful life of the project are relatively insignificant compared to the capital costs. The table also shows that for each route the total operating costs of the proposed project approach between 1990 and 1995 would be $361,500 to $600,150 less than those for low voltage alternative 1 and low voltage alternative 2, with the cost differential depending on the voltage and the route (Exh. HO-RR-5).[10] The analysis indicates that the operating cost savings for the proposed project approach are greater than the capital cost savings of low voltage alternative 2 (id., Tr. 128-129).

Accordingly, the Siting Council finds that the proposed project approach is superior to low voltage alternatives 1 and 2 in terms of cost and that low voltage alternative 2 is superior to low voltage alternative 1 in terms of cost.

c. Environmental Impacts

According to BECo and the MWRA, project alternatives which would utilize a single trench, such as the proposed facilities and low voltage alternative 2, would not have any significant diffences in environmental impact (Tr. 182). Low voltage alternative 1, however, would require two circuits to provide construction power and thus would involve either the digging of two trenches or a single trench twice as wide as that anticipated for the proposed project approach or low voltage alternative 2, according to the Petitioners (Exh. HO-RR-5, Tr. 131). Furthermore, low voltage alternative 1 would have to be replaced or supplemented to provide sufficient capacity for the wastewater treatment facilities' permanent power needs (Exh. BE-1, p. 3-5). This would likely involve a need for additional trenching by 1995. The Petitioners concluded that the additional trenching associated with low voltage alternative 1 would result in a greater impact on the environment (Tr. 131).

The Siting Council finds that the proposed project

10/ The primary reason for these differences in operating costs is the high power losses experienced at lower voltages (Tr. 123). Power losses increase with the square of current and decrease with the square of voltage. The operating costs of the two low voltage alternatives would be similar as long as they are operated at the same power level (id.).

approach and low voltage alternative 2 are comparable in terms of environmental impact and are each preferable to low voltage alternative 1 in terms of environmental impact.

d. Conclusions: Weighing Reliability, Cost and Environmental Impacts

The Siting Council has found that: (1) the proposed project approach, low voltage alternative 1 and low voltage alternative 2 are comparable with respect to reliability; (2) the proposed project approach is preferable to low voltage alternatives 1 and 2 in terms of cost; (3) low voltage alternative 2 is preferable to low voltage alternative 1 with respect to cost; and (4) the proposed project approach and low voltage alternative 2 are comparable in terms of environmental impact and are each superior to low voltage alternative 1 with respect to environmental impact.

Accordingly, the Siting Council finds that the proposed project approach is preferable to low voltage alternatives 1 and 2 in terms of reliability, cost and environmental impacts.

4. Conclusions on the Proposed Project and Alternative Approaches

The Siting Council has found that the Petitioners have demonstrated that the: (1) proposed project approach; (2) low voltage alternative 1; and (3) low voltage alternative 2 each address the identified need for construction power for the planned wastewater treatment facilities on Deer Island. The Siting Council has also found that the: (1) no action alternative; (2) distribution supply from the MECo system in Winthrop; (3) MECo Revere alternative; and (4) on-site generation each fail to address the need for construction power for the planned wastewater treatment facilities on Deer Island.

The Siting Council has also found that the proposed project approach is preferable to low voltage alternatives 1 and 2 in terms of reliability, cost and environmental impacts.

Accordingly, the Siting Council finds that BECo and the MWRA have demonstrated that the proposed project approach is consistent with ensuring a necessary energy supply with a minimum impact on the environment at the lowest possible cost.

III. ANALYSIS OF THE PROPOSED 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. Specifically, a petitioner must demonstrate that its proposed facilities are sited at locations that minimize costs and environmental impacts while ensuring supply reliability.

In previous cases, once the Siting Council has determined: (1) that new energy resources are needed, and (2) that the applicant has proposed a project that is, on balance, superior to alternate approaches in terms of cost, environmental impacts, reliability impacts and addressing identified need, the Siting Council has required the petitioner to show: (1) that it has examined a reasonable range of practical facility siting alternatives, and (2) that the proposed site for the facility is superior to the alternative site(s) on the basis of a balancing of cost, environmental impact, and reliability of supply. 1988 Braintree Decision, 18 DOMSC at 31; 1988 ComElectric Decision, 17 DOMSC at 298-303; 1988 Middleborough Decision; 17 DOMSC at 227-228; NEA, 16 DOMSC at 381-409; 1986 CELCo Decision 15 DOMSC at 195-196, 229-237; 1986 Hingham Decision, 14 DOMSC at 22-32; 1985 MECo Decision, 13 DOMSC at 183-184, 190-248; 1985 BECo Decision, 13 DOMSC at 67-68, 76-81. In past cases, in order to determine that a facility proponent has considered a reasonable range of practical facility siting alternatives, the Siting Council typically has required the proponent to establish that: (1) it has developed and applied a reasonable set of criteria for identifying alternatives, and (2) it has identified at least two practical sites with some measure of geographic diversity. 1988 Braintree Decision, 18 DOMSC at 31-40; 1988 ComElectric

Decision, 17 DOMSC at 301-303; *1988 Middleborough Decision*, 17 DOMSC at 227-228; *Boston Gas Company*, 17 DOMSC 155, 176-181 (1988); *NEA*, 16 DOMSC at 385-388; *1987 CELCo Decision*, 15 DOMSC at 228-229; *1986 Hingham Decision*, 14 DOMSC at 22; *1985 MECo Decision*, 13 DOMSC at 190-191; *1985 BECo Decision*, 13 DOMSC at 76-77.

B. Description of the Proposed and Alternative Facilities

1. Proposed Facilities

The Petitioners preferred facility proposal consists of: (1) a temporary substation to be constructed on Deer Island; (2) a 115 kV transmission line connecting the temporary substation on Deer Island with BECo's K Street substation in South Boston along Route S-1; and (3) a permanent substation on Deer Island to replace the temporary substation by 1995 (Exh. BE-1, pp. 2-2, 2-3). The Petitioners also plan to install line terminal equipment and a 115 kV circuit breaker within the K Street substation to link the proposed transmission line with the existing BECo transmission network (*id.*).

The total length of the proposed route, designated Route S-1, is approximately 21,600 feet, of which approximately 19,800 feet, or 92 percent, is underwater (*id.*, p. 2-3). The cable would be placed underground for all overland portions of the route (*id.*, p. 12-1). As shown in Figure 1, *infra*, Route S-1 would exit the K Street substation in an easterly direction (*id.*). The route would then follow Power House Street, a private roadway, for a short distance (*id.*). At the intersection of Power House Street and Summer Street, Route S-1 would turn north and follow Summer Street for some 200 feet and cross Summer Street near the entrance of the New Boston power plant parking lot (*id.*, p. 5-7). The route would then cross the power plant parking lot and enter the Reserved Channel at a point just east of the Summer Street Bridge (*id.*, p. 2-3).

Route S-1 would then run eastward along the Reserved Channel for approximately 5500 feet and then cross Boston Harbor in a northeasterly direction to Deer Island, where it would pass under an existing road and run directly to the proposed temporary substation (id., Exh. HO-115). The route would parallel the main axis of the Reserved Channel on the south side of the Channel in order to minimize the need for rock trenching (Tr. 160-161). From the eastern terminus of the Reserved Channel, the route would proceed in a straight line to Deer Island except for two minor deviations to avoid a submerged object of potential archeological significance (Exh. HO-138) and a rock outcropping (Tr. 120).

The Petitioners also identified a variation of the proposed route, designated Route S-1A, which is identical to Route S-1 except for the first 2000 feet from the K Street substation (id.). (Exh. BE-1, pp. 2-1 to 2-9). As shown in Figure 1, Route S-1A exits the K Street substation in a northerly direction. The route then passes through a vacant lot owned by BECo without crossing any streets and enters the Reserved Channel at a point approximately 6000 feet west of the eastern end of the Channel (id., p. 2-3; Exh. HO-115). From that point it runs eastward in the Reserved Channel under the Summer Street Bridge and then joins Route S-1 (Exh. BE-1, p. 2-3). The total length of Route S-1A is 21,500 feet, 100 feet shorter than Route S-1 (id.).

The proposed temporary substation would be located on the western side of Deer Island, adjacent to the existing power plant (see Figure 2, infra) (Exh. BE-1, p. 2-2). This substation would consist of 115 kV line terminating equipment, a 115 kV/14kV stepdown transformer and 14 kV bus work and switchgear (id.). It would be an open air facility, using conventional outdoor air-insulated construction for all 115 kV facilities, outdoor metal-enclosed construction for BECo's portion of the 13.8 kV facilities, and a modular building to house protection, control and other necessary ancillary equipment (Exh. HO-21).

The Petitioners identified closed construction as an one alternative configuration for the temporary substation (Exh. HO-21).[11] No alternative sites for the temporary substation were identified in the record.

The temporary substation would be replaced by a larger, permanent substation which would be constructed by 1995 on a site on Deer Island immediately adjacent to the proposed site for the temporary substation (Exh. BE-1, p. 2-2). The Petitioners stated that once the initial construction of the permanent substation is completed, the 115 kV line and the transformer from the temporary substation would be relocated to the permanent substation site (Brief, p. 6; Tr. 148-149).

The Petitioners stated that the intended site of the permanent substation would not be available for the construction of the temporary substation until after construction power is initially required (Tr. 140-142). According to BECo and the MWRA, during the early phases of construction of the new wastewater treatment facilities there will be a great deal of earth-moving and a need to relocate existing facilities in the vicinity of the permanent substation site (Tr. 141). The Petitioners stated that they attempted to resolve construction sequencing to make it possible to site the transformer for the temporary substation at its final location but were unable to do so (Tr. 141-142). The Petitioners also stated that two years or more were required to obtain the switching and bus equipment for the permanent substation (Tr. 141-145). Thus, the permanent substation could not be completed by the time that construction power is required for the startup of major constructon activities on Deer Island.

11/ The Siting Council does not consider enclosed construction of the temporary substation as an alternative facility but will still consider the relative merits of an open versus closed configuration for the temporary substation in its analysis of the proposed facilities. See Sections III.D and III.E, *infra*.

(See Section III.B.3, infra, for a further description of the cables and construction techniques to be employed for the proposed and alternative facilities.)

2. Alternative Facilities

The Petitioners identified one alternative route for the proposed transmission line, designated Route S-2 (Exh. BE-1, pp. 2-3, 2-4). Route S-2 also begins at the K Street substation and terminates at the proposed temporary substation on Deer Island (id., p. 2-4). As shown in Figure 3, infra, however, Route S-2 employs a significantly different route than Route S-1, following public streets through residential, commercial, industrial and recreational areas in South Boston and avoiding the Reserved Channel completely (id.).

Route S-2 exits the K Street substation in an easterly direction and then follows K Street south to East Broadway (id.). It then turns east and follows East Broadway for several blocks to where East Broadway intersects William J. Day Boulevard, which it follows to Marine Park (id.). Route S-2 then crosses the northern portion of the Castle Island recreational area bordering the Fort Independence Historic Site (id.). There it enters Boston Harbor and runs to Deer Island in a submarine trench somewhat to the south of the proposed Route S-1 Harbor crossing (id.). The total length of Route S-2 is approximately 23,100 feet, about 1500 feet longer than Route S-1 (id., pp. 2-3, 2-4). Approximately 10,000 feet, or 43 percent, of Route S-2 is overland (id. p. 2-4).

3. Cables and Construction Techniques

Both the proposed and alternative routes would employ medium-pressure oil-filled cables in ducts for overland sections and medium-pressure oil-filled armored cables in underwater sections (Exh. BE-1, p. 2-3). A total of three cables, each containing a single conductor, would be used to transmit a three-phase alternating current (Exh. HO-126). The cables would be capable of transmitting up to 70 MW of power and therefore would be capable of providing permanent as well as construction power to the Deer Island facility (Exh. BE-1, p. 2-2).

A total of six small oil reservoirs would also be employed to handle changes in the pressure of the insulating oil within the cables (Tr. 161). Each cable would have two dedicated reservoirs, one at each end of the line in Deer Island and South Boston (id.).

The underwater portions of the transmission line would be placed in a single trench, generally at a depth of approximately 15 feet below the harbor bottom (Exh. HO-41). The cables would be laid at a depth of 25 feet below the harbor bottom in the Reserved Channel and the Main Shipping Channel, however, to allow for planned future dredging activities (id., Exh. HO-139). According to the Petitioners, the submarine cable must be buried at these depths in order to avoid possible damage from anchor dragging (Exh. BE-1, p. 12-3). An exception to this plan is the portion of Route S-1A in the Reserved Channel west of the Summer Street Bridge where, due to an inability to use large equipment and the logistics of the site, burial depths in excess of ten feet are not practical (Exh. BE-1, p. 2-4).

The Petitioners stated that construction of the overland portion of either the proposed or alternative routes would conform to standard utility procedures and local regulations (id., p. 12-1). Routes S-1 and S-2 would utilize an underground concrete ductbank for cable burial in South Boston (Exh. HO-43). Route S-1A would not employ a ductbank in South Boston; rather it would employ direct burial of the cables on private property at K Street (id.). All three routes would rely on a combination of ductbank installation and direct burial on Deer Island (Tr. 131).

The cross-section of the overland ductbank would be approximately two feet by three feet in size and would typically be buried in a six foot deep trench and topped with a minimum of four feet of cover (Exh. BE-1, p. 12-2). The Petitioners stated that BECo has extensive experience in ductbank construction for lower voltage transmission lines (Exh. HO-43).

According to the Petitioners, all of the overland portions of Routes S-1 and S-1A and about half of the overland portion of Route S-2 would pass through filled land (Exh. HO-136). No additional soil settlement is expected in these areas (id.). In order to ensure uniform support, however, the Petitioners stated that all land trenches would be overexcavated and filled with at least 12 inches of bedding (id.). The Petitioners stated that the most significant uncertainty associated with overland construction is the potential that special construction techniques will be required for the sections of Route S-2 near Fort Independence (Exh. BE-1, p. 8-3).

The Petitioners stated that special equipment would be required to create a trench in the Harbor bottom and to embed the submarine cables (id., pp. 12-6, 12-7). This equipment would include a hydrojet for plowing through soil, a rock saw for cutting through rock, and two large barges for deploying the hydrojet and rock saw and for cable laying operations (id.). The Petitioners further stated that blasting and conventional dredging would not be required and that 750 feet, or less than four percent, of Routes S-1 and S-1A, would require rock cutting, while Route S-2 would not require any rock cutting (Exhs. HO-40, HO-61, HO-131).

The Petitioners maintained that the plowing of the submarine cable trench would generally require two passes of the hydrojet: an initial trenching run, and a second pass concurrent with cable laying operations to clear the trench of material that had silted-in since the trial run (Exh. BE-1, p. 12-7; Tr. 152-154). Another intermediate pass would be required with the rock saw for those localized areas where rock is encountered (Tr. 152-153).

The Petitioners further stated that a radio tri-sponder system would be used to ensure that the cable is layed accurately along the underwater portions of the proposed or alternative routes (Exh. HO-143). The accuracy of this system in the horizontal plane is plus or minus one meter, according to the Petitioners (id.).

C. Site Selection Process

The Petitioners stated that they employed a two-step screening process for identifying and evaluating facility alternatives and eliminating certain alternatives from further consideration (Tr. 66-68, Brief, pp. 11, 16-17). In the first step of the screening process, BECo and the MWRA evaluated the ability to complete each facility alternative in a timeframe which would make construction power available in time to begin major construction activites within the constraints of the Court Order (Brief, p. 11). All alternatives that failed to meet the required timeframe criterion were eliminated (Tr. 67, Brief, p. 11). As a result of applying this criterion, the Petitioners stated that they eliminated each of the routes associated with the BECo northern route alternative (Brief, p. 16).[12]

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[12] The BECo northern route alternative was considered as a project level alternative by the Petitioners but is considered as a facility alternative herein. See Section II.B.2, supra. The BECo northern route alternative consists of: (1) five alternative overland routes to provide power to Deer Island from BECo's Chelsea substation via a common utility corridor through Revere and Winthrop, designated as Routes N-1A, N-1B, N-1C, N-1D, and N-1E; (2) an alternative route between the Chelsea substation and Deer Island, designated Route N-2, which would require a submarine cable crossing between Orient Heights Beach, near Logan Airport, and Deer Island; and (3) a variant to Route N-2 that would traverse Logan Airport (Exhs. BE-1, pp. 3-6 to 3-7; BE-8, p. 2-12).

In the second step of the screening process, BECo and the MWRA stated that they performed a detailed analysis of the three remaining routes which could potentially provide construction power within the required timeframe: the proposed route, designated Route S-1; a variation of the proposed route, designated Route S-1A; and an alternative route, designated Route S-2 (Exh. BE-1, pp. 2-1 to 2-9; Tr. 67; Brief, p. 17)

BECo and the MWRA stated that they used the following criteria in the second step of their screening process to evaluate the proposed and alternative facilities:

(1) Reliability, including (a) the intrinsic reliability of the transmission line and appurtenant equipment, and (b) the impact that the facilities would have on the source utility generation and transmission system;

(2) Costs, including (a) capital costs, (b) operating costs, (c) "timely implementation," defined as the relative difficulty in maintaining the project schedule, and (d) the difficulty and duration of construction;

(3) Environmental considerations, including (a) land resources, such as impacts on land use and zoning, terrestial ecology, wetlands and floodplains, and historical and archeological resources, (b) marine resources, such as impacts on water quality/sediment chemistry, marine biota and marine archeological resources, (c) traffic, including vehicular and marine traffic, and (d) noise;

(4) Institutional considerations, including (a) permit requirements, (b) the degree of coordination required between the Petitioners and external agencies, (c) the degree of coordination required between BECo and the MWRA, and (d) the demand for unique or scarce resources, such as the availability of scarce labor skills and equipment

(Exh. HO-1, pp. 4-1 to 4-5).

The Petitioners stated that they developed these criteria based on input from the MWRA's Secondary Treatment Facilities Planning Project Team, the Massachusetts Executive

Office of Environmental Affairs and the Citizens Advisory Committee (Exh. HO-29; Brief, p. 19). The Petitioners further stated that each of the criteria was weighted equally in deriving an overall evaluation of the proposed and alternative facilities (Exh. HO-133). The Petitioners did not offer a justification for their decision to weight all of the criteria equally.

The Petitioners stated that they also examined and rejected a variant to Route S-2 that would travel along East First Street through South Boston rather than East Broadway (Exh. HO-86). The Petitioners stated that this route was not viable since there was not adequate space available between existing utilities in East First Street to locate the proposed ductbank (id.).

BECo and the MWRA stated that they did not consider any route traversing the industrial properties to the north of Route S-2 between East First Street/William J. Day Boulevard and the Reserved Channel (Exh. HO-88). The Petitioners stated that they did not consider such a route because the time and cost constraints which would be involved in negotiating easements with six to eight landowners (id.). The Petitioners further stated that construction through this area likely would make it difficult for the MWRA to meet the Court-ordered schedule (id.).

In predicating the initial step of its site selection process on timing considerations, the Petitioners place far more reliance on timing than have other applicants before the Siting Council. In fact, while the Siting Council has recognized implementation and timing considerations as potentially legitimate factors in comparing a proposed and alternative site (NEA, 16 DOMSC at 388-390, 408; 1988 ComElectric Decision, 17 DOMSC at 229-343), it has indicated that it would be difficult for a private entity to support a screening analysis that exclusively or primrily relies on these factors (Turners Falls, 18 DOMSC at 179 n.24). And, the Siting Council never has indicated that short-term timing considerations are appropriate criteria for eliminatng a whole range of otherwise viable options at the site screening level.

The present application, however, is different not just in degree but in kind from those that preceeded it. Here, a sister agency has petitioned the Siting Council to approve a necessary element of its central undertaking - the clean-up of Boston Harbor. As indicated in Section II.A.2, <u>supra</u>, each month that passes without improved wastewater treatment facilities results in additional inadequately treated sewage being released into Boston Harbor with a concomitant additional cost to the people of the Commonwealth. In addition, a federal court, after reviewing years of little progress in cleaning the Harbor, has ordered work on the new wastewater treatment facilities to proceed according to a vigorous schedule (see Exh. HO-1).

While even a public entity engaged in carrying out a public policy goal must carefully weigh long-term goals against short-term timing considerations and must not manage a project schedule so as to eliminate otherwise viable options, the circumstances of this case are such that the Siting Council finds that the Petitioners initial site selection criterion is acceptable.

Accordingly, the Siting Council finds that the Petitioners have developed a reasonable set of criteria for identifying facility siting alternatives for the proposed 115 kV transmission line and that these criteria minimize the costs and environmental impacts of constructing and operating the needed energy facility.

The Siting Council also finds that the Petitioners have identified at least two practical alternatives with some measure of geographic diversity for the 115 kV transmission line. Almost half of the length of Route S-2 is overland, while Route S-1 runs underwater for about 96 percent of its length.

The Siting Council, however, notes two concerns with the Petitioners' site selection process. First, the Petitioners could have considered a broader range of route alternatives, such as a route crossing the industrial properties between the Reserved Channel and East First Street. Second, while finding the criteria employed by Petitioners acceptable in this case, the Siting Council is concerned that the Petitioners did not offer any justification for the weighting of criteria used in the second step of the screening process. A proponent's weighting of its chosen screening criteria clearly has a direct and significant impact on the final site selection. Without a showing of how the weights were assigned, the Siting Council cannot conclude that the site selection process is unbiased and consistent with achieving a balance between necessary energy supplies, cost and environmental impacts. In future cases, proponents should demonstrate how the weighting of site selection criteria was developed and how their weights ensure that the Commonwealth's siting objectives are achieved.

Nonetheless, for the purposes of this decision, the Siting Council has found that the Petitioners have established that they: (1) developed and applied a reasonable set of criteria for siting the proposed 115 kV transmission line; and (2) considered at least two practical alternatives with some measure of geographic diversity.

D. Reliability Analysis of the Proposed and Alternative Facilities

BECo and the MWRA stated that the reliability of electric power to serve the construction and operating needs of the planned waste treatment facilities is of critical importance (Exh. BE-1, p. 7-1). They stated that they considered two aspects of reliability in their analysis: (1) the intrinsic reliability of the transmission facility itself; and (2) the impact that construction of the transmission facility would have on the reliability of the source system (id., p. 4-1). In its reliability analysis, infra, the Siting Council evaluates these two aspects of reliability as well as a third aspect of reliability related to the potential for delay in the construction of the proposed and alternative facilities (<u>see</u> <u>1988 ComElectric Decision</u>, 17 DOMSC at 339-341).[13]

1. <u>System Reliability</u>

The Petitioners stated that both the proposed and alternative transmission facilities would have a capacity of 70 MW, sufficient to support the long-term operating requirements of the Deer Island facilities as well as the 15 MW of construction power required (Exh. BE-1, p. 2-2; Exh. HO-45). According to BECo and the MWRA, the K Street substation is readily capable of supplying the required power (Exh. BE-1, p. 7-2, Exh. HO-45). The substation is connected to the 700 MW New Boston generating plant and there are also six 115 kV transmission lines and a 345 kV transmission line in the vicinity which tie into the regional transmission network and can provide support to the MWRA load (Exh. HO-45).

The Petitioners further stated that the 15 MW required for construction power is small in comparison with the downtown Boston area load and in fact would be less than the average annual growth experienced in the area (<u>id.</u>). BECo expects to continue to augment its generation system to accommodate the increased load (Exh. HO-46).

Moreover, the Petitioners stated that once full operation of the waste treatment facility begins, the loading on the transmission line would be reduced because it would be split with another source (Exh. BE-1, p. 7-2). Also, the MWRA and BECo maintained that the peak power needs of the waste treatment facility are not expected to be coincident with BECo's peak load (Exh. HO-46).

13/ The Petitioners included a similar criteria in their evaluation which they termed "timely implementation" (Exh. BE-1, p. 7-1). However, they placed this evaluation criteria under cost rather than reliability (<u>id.</u>).

Accordingly, the Siting Council finds that the proposed and alternative facilities are comparable with respect to their impact on BECo's system reliability and that the impact of these facilities on BECo's system reliability is acceptable.

2. Intrinsic Reliability of the Proposed and Alternative Facilities

The Petitioners stated that both the proposed and alternative routes would utilize cables of the same design and therefore would be of equivalent reliability (Exh. BE-1, pp. 7-1, 7-2). The Petitioners also provided that the land and submarine cables were also of the same design except for some additional outer sheathing for the submarine cable which would have no effect on the cable's reliability (Tr. 164-165).

According to BECo and the MWRA, cables of this type have been manufactured for over 30 years, have been widely installed throughout the world, and have an excellent reliability record (Exh. BE-1, p. 7-1). The minimum life expectancy for the cables is 40 years and their expected outage rate is zero (Exh. HO-125). The major reasons for submarine cable failures in the past have been associated with cables layed on the sea bottom without protective cover or with underwater cable joints (id.). The proposed and alternative facilities are designed to avoid these potential problems (id.).

With respect to the temporary substation, the Petitioners stated that enclosed construction would provide greater long-term operating reliability than open air construction but that reliability problems due to salt spray and other contaminants were not a concern for the two- to three-year period before the temporary substation would be replaced (Exh. HO-21, Tr. 143).

Accordingly, the Siting Council finds that the intrinsic reliability of the proposed and alternative facilities is acceptable. The Siting Council also finds that the intrinsic reliability of the proposed and alternative routes is comparable and that the reliability of a closed configuration for the temporary substation is slightly preferable to the reliability of the proposed open air configuration for the temporary substation.

3. Potential for Delay in Construction of the Proposed and Alternative Facilities

The MWRA and BECo are seeking to place the proposed facilities in service by mid-to-late 1990 in order to expedite the construction of waste-treatment facilities which depend on electrical power. Specifically, the completion of the outfall tunnel, which the court schedule presently requires to be completed by July 1995, is dependent on the construction of additional electric transmission facilities (Exhs. HO-1, HO-68). The Petitioners concluded that construction of Routes S-1 and S-1A could be completed more expeditiously than construction of Route S-2 (Exh. BE-1, p. 10-2). This is because, according to the Petitioners, Route S-2 would be expected to require a more extensive regulatory review and approval process than either Route S-1 or S-1A. Route S-2 passes through densely populated residential areas in South Boston as well as through highly visible recreational space in Marine Park and Castle Island (_id._, p. 8-2).

With respect to the temporary substation, the Petitioners stated that longer lead times would be involved in the design and construction of an enclosed facility than the proposed open air facility (Exh. HO-21).

For the reasons set forth in Section III.C, _infra_, the Siting Council accepts the need, in this case, to review the implementation and timing considerations associated with the proposed and alternative route. As a result of this review, the Siting Council finds that Routes S-1 and S-1A are comparable in terms of the potential for delay in construction and that both are preferable to Route S-2 in this regard. The Siting Council also finds that the proposed open air temporary substation is slightly preferable to the enclosed substation in terms of timely implementation.

4. Conclusions on the Reliability Analysis of the Proposed and Alternative Facilities

The Siting Council has found that: (1) the proposed and alternative facilities are comparable with respect to their impact on BECo's system reliability; (2) the intrinsic reliability of the proposed and alternative routes is comparable; and (3) Routes S-1 and S-1A are comparable in terms of the potential for delay in construction and that both are preferable to Route S-2 in this regard.

Overall, the Siting Council finds that Route S-1 and S-1A are comparable with respect to reliability and are preferable to Route S-2 with regard to reliability.

The Siting Council has also found that: (1) the intrinsic reliability of enclosed construction for the temporary substation is slightly preferable to the reliability of the proposed temporary open-air substation; and (2) the proposed temporary open-air substation is slightly preferable to the enclosed substation in terms of timely implemention.

On balance, the Siting Council finds that the proposed temporary open-air substation and the enclosed substation are comparable with respect to reliability.

E. Cost Analysis of the Proposed and Alternative Facilities

The Petitioners presented estimated capital costs for Routes S-1 and S-1A of $14,781,195 and $15,430,025, respectively, in current (1989) dollars (Exhs. HO-24, HO-144). These figures were based on the results of a construction bidding process held by BECo (Exhs. HO-24, HO-84). Each of the bidders quoted a cost for Route S-1 that was less than the cost of Route S-1A (Exh. HO-84). BECo did not request bids for

Route S-2 but estimated a capital cost of $17,571,625 in current dollars for that route based on the unit rates of the winning bidder (Exh. HO-24). Thus, the estimated capital costs for Route S-1A and Route S-2 were approximately 4.4 percent and 18.9 percent higher, respectively, than the estimated capital costs for Route S-1.

BECo and the MWRA stated that they did not perform a life-cycle cost analysis of the various routes because operation and maintenance costs and line losses for each of the routes would be similar; therefore, capital costs would be the only significant variable in a life cycle cost analysis (Exh. HO-105).

The Petitioners further stated that the direct cost of the required modifications to the K Street substation would be $905,000 and the direct cost of constructing the proposed temporary open-air substation on Deer Island would be $1,754,000, both figures expressed in 1990 dollars (Exh. HO-50). BECo's charges for indirect costs would add 30 to 35 percent to these estimated direct costs (Tr. 150). The Petitioners also stated that with respect to the temporary substation, closed construction would be more expensive than open air construction, although the difference in cost was not quantified (Exh. HO-21).

Accordingly, the Siting Council finds that: Route S-1 is preferable to Routes S-1A and S-2 in terms of cost, and Route S-1A is preferable to Route S-2 in terms of cost. The Siting Council also finds that the open air construction proposed for the temporary substation is preferable to closed construction in terms of cost.

F. Environmental Analysis of the Proposed and Alternative Facilities

1. Land Resources

BECo and the MWRA identified the following categories of environmental impacts on land resources: (1) land use and zoning; (2) terrestial ecology; (3) wetlands and flood plains; and (4) historic and archeological resources (Exh. BE-1, pp. 5-1 to 5-6).

With respect to land use and zoning, the Petitioners stated that all of the routes under consideration originate at K Street in South Boston and terminate at the proposed substation on Deer Island following a submarine Harbor crossing (Exh. BE-1, pp. 5-1, 6-1). Therefore, the Petitioners stated, the major differences between the routes is that Route S-2 would travel through densely populated urban residential and commercial areas and the Marine Park and Castle Island recreational areas, whereas Routes S-1 and S-1A would enter the Reserved Channel directly from K Street after passing through either an industrial area for a short distance (Route S-1) or vacant land (Route S-1A) (id.). BECo and the MWRA further stated that in contrast to Route S-2, neither Route S-1 nor S-1A would pass through any sensitive land uses (id.).

The Petitioners also contended that Routes S-1 and S-1A would have a minimal impact on terrestial ecology, whereas Route S-2 would have a moderate impact on terrestial ecology (id., p. 10-2). The Petitioners stated that Routes S-1 and S-1A would pass near little vegetation but that Route S-2 would disrupt a recently landscaped area and ornamental tree plantings adjacent to Fort Independence (id., pp. 5-3, 6-1, 6-2). According to the Petitioners, no unique or important plant or animal species inhabit areas along the land portions of any of the routes under consideration (id., pp. 5-3, 6-1).

The Petitioners argued that Route S-1 would have a minimal impact on wetlands and floodplains and Routes S-1A and S-2 would have a moderate impact on such resources (id., pp. 6-2, 10-2). According to BECo and the MWRA, construction along Routes S-1 and S-1A would occur within the 100-year floodplain near the K Street substation but most of this construction would be underwater (id., p. 6-2). Route S-1 would cross an area of filled tideland above the 100-year flood elevation prior to entering the Reserved Channel through a bulkhead (id.). Route S-1A would cross an intertidal area of the Reserved Channel that the Petitioners stated is degraded and of little ecological value (id.). BECo and the MWRA stated that no loss of sensitive plant or animal species would result from construction in this area (id.).

Route S-2 passes through the floodplain as it proceeds along William J. Day Boulevard to Fort Independence as well as an intertidal area adjacant to Fort Independence (id.). The Petitioners judged this intertidal area to be more valuable than the intertidal area crossed by Route S-1A in the Reserved Channel (id.).

Routes S-1, S-1A and S-2 each would traverse an intertidal area where the cable would come ashore on the western side of Deer Island (id., p. 5-4). According to the Petitioners, this area is classified as an estuarine intertidal flat with an unconsolidated bottom (id.). The Petitioners stated that no tidal wetlands or sensitive marine ecological resources appear to be present in this area (id.).

Based on field inspection of the routes and historical and archeological surveys, the Petitioners rated the impact of overland cable construction on historical and archeological resources as minimal for Routes S-1 and S-1A and as moderate to significant for Route S-2 (id., pp. 6-2, 6-3, 10-2). The Petitioners stated that no historic resources were identified for the overland portions of Route S-1 and S-1A and sensitive archeological resources were limited to walls and wharves bordering the Reserved Channel which would not be affected by the project (id., p. 6-2).

The Petitioners identified several historic and archeological sites along Route S-2 (id., p. 5-6). The Petitioners stated that construction of Route S-2 would result in moderate impacts on historic sites and districts in South Boston and potentially significant impacts in the Fort Independence area due to the proximity of the route to the original seawall (id., p. 6-3). The Petitioners further stated that extensive archeological studies and special care during excavation would be required in this area, thus potentially leading to delays in the licensing and construction schedule for this route (<u>id.</u>).

Based on the foregoing, the Siting Council finds that Routes S-1, S-1A and S-2 are each acceptable with respect to their impact on land resources. The Siting Council also finds that Routes S-1 and S-1A are comparable in terms of their impact on land resources. The record indicates that Route S-2 would have a more significant impact on land use and zoning, terrestial ecology, wetlands and floodplains, and historical and archeological resources than Routes S-1 and S-1A.

2. <u>Marine Resources</u>

The Petitioners identified several adverse effects of submarine cable construction on marine resources, including impacts on water quality, marine biota and marine archeology. BECo and the MWRA asserted, however, that these impacts would be very localized and of short duration - primarily during and shortly after the trenching operations - and therefore that the overall impacts of cable construction on marine resources would be small (Exh. BE-1, pp. 6-6 to 6-12, 10-1 to 10-2). These impacts are discussed below.

a. <u>Water Quality/Sediment Chemistry</u>

The Petitioners stated that submarine transmission line construction would result in the temporary resuspension of bottom sediments and that chemical constituents within these sediments, including Polychlorobiphenyls ("PCB's"), Polycyclic Aromatic Hydrocarbons ("PAH's") and metals, would potentially effect water quality (Exh. BE-1, p. 6-10). The Petitioners stated that they modeled the sediment resuspension process, and, based on the results of this modeling effort, predicted that resuspension should be minimal and very localized and that redeposition should occur fairly soon after the passage of the hydro-jet (Exhs. BE-1, pp. 6-7, 6-10; BE-8, p. 6-25).

Based on studies performed by the MWRA, the Petitioners contended that the resuspension of harbor-bottom sediments would be less significant than that occuring naturally during coastal storms (Exhs. BE-1, p. 6-10, HO-124). According to the Petitioners, water turbidity is normally a more significant concern with rock trenching (id.). However, the Petitioners indicated that rock trenching will be needed for only 4 percent of Routes S-1 and S-1A and not at all for Route S-2 (Exh. HO-40).

The EPA and the Division of Water Pollution Control ("DWPC") of the Massachusetts Department of Environmental Protection ("DEP") have raised concerns regarding the concentrations of PCB's and PAH's found in portions of the Reserved Channel (Exhs. BE-1, pp. 5-21, 5-25, 5-42; BE-8, p. 6-4; Tr. 184). A 1982 study performed by the DWPC reported PCB concentrations of up to 35 parts per million ("ppm") west of the Summer Street Bridge, approximately one-fifth of a mile away from the point where Route S-1A enters the Reserved Channel (Exh. HO-146, Tr. 176)[14].

The Petitioners performed more recent sediment surveys which detected PCB concentrations ranging from 1 to 3 ppm in the vicinity of the proposed and alternative routes (Tr. 184, 185). Despite the results of these surveys, the Petitioners stated that the DWPC had cautioned them that Route S-1A may not be permitted by that agency due to the proximity of Route S-1A to areas where high PCB concentrations had been detected in the sediments (Tr. 182-185; Exh. BE-8, p. 6-17).

14/ Materials with PCB concentrations of 50 ppm or greater are considered toxic substances and consequently come under the jurisdiction of the Toxic Substance Control Act. These substances must be disposed of in a specialized manner (Tr. pp. 186-187).

BECo and the MWRA also presented surveys done by DWPC on the concentration of non-organic compounds in the water column which indicated that several compounds had detection limits higher than EPA's water quality criteria (Exh. BE-1, p. 5-18).

Water quality could also be affected if the submarine cables were accidently cut by an anchor, and the oil contained in the cables leaked out (Tr. 161, 162). The Petitioners asserted, however, that the cables would be enclosed in a thick protective sheathing, that they would also be embedded deep enough to avoid damage, and that in any case each cable contained only 400 gallons of oil (Tr. 161, Exh. HO-82).

Based on the foregoing, the Siting Council finds that the impacts on water quality associated with submarine cable construction are acceptable for each of the routes. The Siting Council also finds that: (1) Route S-2 is preferable to Route S-1 in terms of its impact on water quality because of the greater length of Route S-1 underwater and the need for rock trenching along a small portion of Route S-1; and (2) Routes S-1 and S-2 are preferable to Route S-1A with regard to water quality impacts because of the proximity of a portion of Route S-1A to areas where high levels of PCB's have been found.

b. Marine Biota

The Petitioners asserted that submarine construction would disturb benthic (bottom dwelling) fauna in Boston Harbor to a moderate degree. According to BECo and the MWRA, however, impacts on marine biota would be localized and of short duration (Exh. BE-1, pp. 6-10). These impacts would include a temporary loss of habitat, damage to organisms from trenching, and potential contamination as a result of the resuspension of contaminated sediments.

The Petitioners stated that the use of the hydro-jet for trenching would ameliorate many of the consequences usually associated with submarine cable installation using conventional dredging techniques (Exh. BE-1, pp. 6-5 to 6-11). The

Petitioners asserted that the embedding operations will lead to a temporary disturbance to about 1 to 2 acres of benthic habitat along each of the routes, with disturbances being somewhat higher for Routes S-1 and S-1A because of their greater length underwater compared to Route S-2 (Exh. BE-1, p. 6-7).

Several environmental regulatory agencies raised concerns regarding the potential impact of submarine cable construction on the spawning and nursery habitat of the winter flounder (Exhs. BE-8, p. 6-7, BE-15). The Petitioners stated that the Boston Conservation Commission requested that, for any construction in the Harbor, the Company use its best efforts to avoid the winter flounder spawning season, which begins in February and ends in May (Exhs. HO-107, BE-15; Tr. 29-33, 178-181). If cable embedment cannot be completed prior to the beginning of the spawning season, one option for Petitioners is to resume submarine construction in mid-May, when the spawning season ends (Tr. 32, 33).[15] The Petitioners stated that they expect to meet the construction schedule, which sets February 10, 1990 as the completion date for cable embedment operations, and that the schedule takes potential delays into account in setting this date (Tr. 31-33).

BECo and the MWRA indicated that the resuspension of contaminated sediments would have a minimal negative impact on commercially valuable species such as flounders, lobsters or shell-clams (Exhs. BE-1, p. 2-3, HO-83). The Petitioners stated that PCB concentrations along any of the routes are well below the federal action level for fish and shellfish and that

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15/ According to the record, various regulatory agencies have defined the dates of the winter flounder spawning season differently (Exhs. BE-1 pp. 5-27, 6-7; BE-8, p. 6-12; Tr. 30). The record is unclear as to whether the Petitioners may continue cable construction into the winter flounder spawning season absent additional permits (see Tr. 31-32, 178-181).

PCB's are not expected to bioaccumulate in marine fauna in any appreciable amount (Exh. HO-108).

Each of the routes would cross an area of "sensitive marine resources", consisting primarily of seaweed, just to the west of Deer Island (Exh. HO-109). According to the Petitioners, the impact of submarine cable construction on this area would be temporary and the area would quickly return to its original conditions (id.).

The Siting Council finds that the impact of submarine cable construction on marine biota would be acceptable along either Route S-1, Route S-1A or Route S-2. The Siting Council also finds that: (1) Route S-2 is preferable to Route S-1 with respect to its impact on marine biota due to the lack of rock trenching and the shorter submarine length of Route S-2; and (2) both Route S-1 and Route S-2 are preferable to Route S-1A in terms of their impact on marine biota because of the closer proximity of Route S-1A to areas where high levels of PCBs have been detected and the risk to marine biota associated with the potential resuspension of PCB-contaminated sediments.

c. Marine Archeology

The Petitioners stated that the impact of submarine cable construction on marine archeology should be minimal along each route (Exh. BE-1, p. 10-2). BECo and the MWRA stated that they had reviewed numerous studies of the marine archeology of Boston Harbor and concluded that few of the Harbor's archeological resources are located in the vicinity of any of the routes (id., p. 5-48). An additional study completed by the Petitioners in early 1989 revealed a submerged object of potential archeological interest near the original S-1 route (Exh. HO-138). The route was subsequently altered to avoid this object and Route S-1, as currently proposed, will deviate 100 feet from the object (id.). The Petitioners stated that aside from this object, there seems to be no other evidence of archeologically valuable marine resources in the vicinity of the submarine portions of any of the routes under consideration (Exhs. BE-1, p. 5-48, HO-138).

The Massachusetts Historical Commission indicated in a letter to the MWRA that the construction of the proposed submarine transmission line is unlikely to have an impact on marine archeological resources and concluded that no further archeological investigation of the project is recommended (Exh. BE-14).

Based on the information presented above, the Siting Council finds that the Petitioners have established that the impact of submarine cable construction on marine archeological resources along Routes S-1, S-1A or S-2 would be acceptable. The Siting Council also finds that each of the routes is comparable in terms of impact on marine archeological resources.

d. Conclusions on Marine Resources

The Siting Council has found that: (1) Routes S-1 and S-2 are preferable to Route S-1A, and Route S-2 is preferable to Route S-1 in terms of their impact on water quality and marine biota; and (2) all three routes are comparable in terms of their impact on marine archeological resources.

Overall, the Siting Council finds that Routes S-1 and S-2 are preferable to Route S-1A, and Route S-2 is preferable to Route S-1 in terms of their impact on marine resources.

3. Traffic and Other Impacts

a. Vehicular Traffic

The Petitioners surveyed current traffic flow and parking patterns on roadways which would be affected by the construction of the overland portion of the proposed and alternative transmission line routes (Exh. BE-1, pp. 5-6 to 5-10).

BECo and the MWRA stated that Route S-1 will affect traffic only on Summer Street, which it will follow for approximately 200 feet, and Powerhouse Street, a short private roadway which is used by vehicles accessing industrial buildings which abut the road (id., p. 5-7). Road construction on Summer Street is expected to take three or four weeks (Exh. HO-112).

Route S-1A does not traverse any roadways and consequently would not involve any disruption to vehiculartraffic (id., Exh. BE-1, p. 5-7).

The Petitioners stated that, in contrast, Route S-2 requires approximately 8700 feet of roadway construction along three roads in South Boston: William J. Day Boulevard, Broadway, and K Street (Exh. BE-1, p. 6-3). There is extensive use of on-street parking on each of these streets and peak hour traffic volumes are 900, 1600 and 200 vehicles per hour, respectively (id.). The Petitioners estimated that construction along the land portion of Route S-2 would take from six months to one year, depending on weather conditions and traffic restrictions, resulting in a prolonged period of traffic and parking disruptions (id., pp. 6-3, 6-4; Exh. HO-112).

Based on this analysis, the Petitioners rated the overall traffic impacts from construction as moderate for Route S-2 and as minimal for Route S-1. BECo and the MWRA also concluded that construction of Route S-1A would have no traffic impacts (Exh. BE-1, pp. 6-3, 10-2).

The Siting Council finds that the Petitioners have established that construction of the proposed transmission line along any of the proposed or alternative routes would have an acceptable impact on vehicular traffic. The Siting Council also finds that either Route S-1 or S-1A is highly preferable to Route S-2 with respect to vehicular traffic impacts.

b. Marine Traffic

The Petitioners stated that they surveyed marine traffic flow in Boston Harbor to estimate the impact of submarine cable construction on the movement of ships (id., pp. 5-7, 5-11, 5-13). They determined that most of the impact on shipping likely would occur in the Main Shipping Channel, the major concourse for large vessels travelling into and out of Boston Harbor, which would be traversed by all of the proposed transmission line routes under consideration (id., p. 6-4).

The Petitioners further stated that approximately 88 percent of the ships passing through Boston Harbor have drafts of less than 18 feet and thus would not be confined to travel within the boundaries of the Main Shipping Channel (id.). Therefore, according to the information provided by BECo and the MWRA, disruption to marine traffic in the Main Shipping Channel should be limited to a daily average of two to three vessels which have a draft of 18 feet or more and so must pass through the channel to enter or leave the Harbor (Exh. HO-117).[16]

BECo and the MWRA stated that Routes S-1 and S-1A would cross approximately 1800 feet of the Main Shipping Channel while Route S-2 would cross about 1400 feet of the Channel (Exhs. HO-116, HO-36). Construction along each of the routes within the Main Shipping Channel would require two passes with the hydrojet, but no rock trenching is believed to be required in the Channel (Exhs. BE-1, p. 12-7, HO-131). Given a construction rate of 600 feet per day for the hydrojetting operation, construction time in the Main Shipping Channel would total approximately six days for Routes S-1 and S-1A and 4.6 days for Route S-2 (Exhs. HO-116, HO-36, Tr. 156-157). The passage of deep draft marine traffic through the Main Shipping

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16/ The Petitioners also stated that a maximum of nine deep draft vessels pass through the Main Shipping Channel on a given day.

Channel would be impaired significantly during much of this interval since up to 600 feet of the channel width would be occupied by the two construction barges (Exh. HO-118, Tr. 157). The Petitioners stated, however, that the estimates for total construction time are based on a twelve hour workday and that it may be possible to work extended hours in order to reduce the impact of transmission line construction on marine traffic (Exh. HO-142). The Petitioners also stated their intent to inform the Boston Harbor Master, Coast Guard and Boston Pilot's Association of construction activities and to closely coordinate construction activities in the Main Shipping Channel with planned vessel arrivals and departures (Exh. HO-118).

According to the Petitioners, marine traffic in the Reserved Channel is not expected to be significantly impeded by construction of the submarine cable along Routes S-1 or S-1A (Tr. 160). Route S-2 does not pass through the Reserved Channel. The Petitioners stated that construction in the Reserved Channel will take place parallel to the movement of ships in the Channel and the Channel is sufficiently wide to permit the passage of ships while construction is in progress (Tr. 159-160, Exh. HO-114). While construction of the portion of either Route S-1 or S-1A in the Reserved Channel is expected to take more than 30 days, the Petitioners asserted that on any given day few ships travel in the Channel (Exh. HO-113). BECo and the MWRA stated that they would work closely with various harbor authorities to coordinate construction in the Reserved Channel with shipping activities (Exh. HO-114).

Accordingly, the Siting Council finds that Routes S-1, S-1A and S-2 are each acceptable with respect to the impact that they would have on marine traffic. The Siting Council also finds that Route S-2 is preferable to Routes S-1 and S-1A in terms of marine traffic impacts because of the shorter construction time for Route S-2 in the Main Shipping Channel and because Route S-2 does not pass through the Reserved Channel. The Siting Council finds that Routes S-1 and S-1A are comparable in terms of their impact on marine traffic.

c. Noise

The Petitioners stated that noise impacts will be limited to noise produced during construction (Exh. BE-1, p. 5-14). The MWRA and Boston Edison indicated that they will comply with established guidelines for noise control, and will examine the need for noise abatement throughout the design, construction and operation of the proposed facility (id., p. 11-1).[17]

The Petitioners stated that Routes S-1 and S-1A have minimal noise impacts associated with submarine cable construction (Exh. BE-1, p. 6-5). Nearly all of the construction for these two routes would be offshore and would be more than 2000 feet from residential areas (id.). The maximum construction noise level for these routes at the nearest commercial or residential receptor would be less than 60 decibels ("dB"), while the maximum noise level at the Castle Island recreational area would be 66 dB (Exhs. BE-1, p. 5-15, HO-20).

BECo and the MWRA indicated that Route S-2 would have a high noise impact on residential areas in South Boston from overland construction as well as a greater noise impact from submarine construction due to the proximity of portions of this route to the Castle Island recreational area (Exh. BE-1, p. 6-5). Maximum noise levels for Route S-2 at the nearest residential or commercial receptor are reported to be 84 dB for excavation on land, 86 dB for paving, and 71 dB for submarine cable construction (id., p. 5-15). Route S-2 would also require a considerably longer period for overland construction and associated noise impacts would thus be prolonged (Exh. BE-1, p. 8-2).

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[17] The Petitioners stated that the City of Boston's Noise Code specifies that noise levels for street excavation may not exceed 86 decibels at a distance of 15 meters from the construction device and are limited to 50 decibels at the residential property line at night and on weekends (Exh. BE-1, p. 5-14).

The Siting Council finds that each of the routes is acceptable with respect to noise impacts because each would be in compliance with the City of Boston's noise regulations. The Siting Council also finds that Routes S-1 and S-1A are highly preferable to Route S-2 with respect to noise impacts, due to the lower maximum noise levels as well as the shorter duration of noise impacts for construction along these routes.

d. Visual Impacts

The Petitioners stated that there will be no negative long-term visual impacts associated with the proposed and alternative transmission lines because the transmission cables would be buried underground or beneath the harbor bottom. Similarly, BECo and the MWRA stated that there would be no visual impacts associated with the proposed temporary and permanent substations as both would be shielded from public view (Exh. BE-1, p. 6-12).

The Siting Council finds that the Petitioners have established that a transmission line along the proposed or alternative routes would have an acceptable visual impact. The Siting Council also finds that the proposed temporary and permanent substations would have an acceptable visual impact. For both the routes and the substations, the impacts are comparable.

4. Conclusions on the Environmental Analysis of the Proposed and Alternative Facilities

The Siting Council has found that the environmental impacts of constructing and operating the proposed and alternative routes would have an acceptable impact on land resources, marine resources, vehicular traffic and marine traffic and would also result in an acceptable level of noise and visual impacts.

In addition, the Siting Council has found that: (1) Routes S-1 and S-1A are comparable and are preferable to Route S-2 with respect to their impacts on land resources, vehicular traffic and noise; (2) Route S-2 is preferable to Routes S-1 and S-1A in terms of its impact on marine traffic, and Routes S-1 and S-1A are comparable in this regard; and (3) Route S-2 is preferable to Route S-1, and Route S-1 is preferable to Route S-1A, with respect to their impacts on marine resources.

The Siting Council finds, on balance, that the Route S-1 is superior to the alternative routes with respect to environmental impacts. The Siting Council makes no finding with regard to the relative environmental impacts of the open air design and closed design for the temporary substation.

G. Conclusions on the Analysis of the Proposed and Alternative Facilities

The Siting Council has found that BECo and the MWRA have considered a reasonable range of practical facility siting alternatives for the proposed 115 kV transmission line. In addition, the Siting Council has found that: (1) the proposed route (Route S-1) is comparable to Route S-1A and preferable to Route S-2 on the basis of reliability; (2) Route S-1 is superior to Routes S-1A and S-2 with respect to cost; and (3) Route S-1 is preferable to Routes S-1A and S-2 in terms of environmental impact.

Based on the foregoing, the Siting Council finds that Route S-1 is superior to Routes S-1A and S-2 on the basis of reliability, cost and environmental impact.

The Siting Council has also found that: (1) the proposed open air configuration for the temporary substation and the closed design for the substation are comparable in terms of reliability; and (2) the open air design for the temporary substation is superior to the closed design in terms of cost. The Siting Council has made no finding with respect to the relative environmental impacts of the open air design and the closed design for the temporary substation. Based on the foregoing, the Siting Council finds that the proposed open air design is superior to the closed design for the temporary substation.

In order to mitigate the potential impact of the proposed 115 kV transmission line on marine traffic and on historical and archeological artifacts, the Siting Council ORDERS BECo and the MWRA to:

(1) inform the Boston Harbor Master, Coast Guard, Boston Pilots Association, all abutters to the Reserved Channel east of the Summer Street Bridge, and other appropriate shipping interests of their construction plans and closely coordinate submarine construction activities in the Reserved Channel and Main Shipping Channel with planned vessel arrivals and departures; and

(2) fulfill all requirements of the Massachusetts Historical Commission regarding land portions of the approved route.

IV. DECISION AND ORDER

The Siting Council finds that: (1) the construction of a single-circuit, 4.15 mile, underwater/underground 115 kilovolt transmission line along the proposed route (Route S-1); (2) the construction of a temporary open air substation at the proposed site on Deer Island described herein; and (3) the construction of a permanent substation to replace the temporary substation by 1995 at the proposed site on Deer Island described herein are consistent with providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

Accordingly, the Siting Council hereby APPROVES the petition of Boston Edison Company and the Massachusetts Water Resources Agency to construct: (1) a single-circuit, 4.15 mile, underwater/underground 115 kV transmission line along the proposed route; (2) a temporary substation on the proposed site on Deer Island described herein; and (3) a permanent substation to replace the temporary substation by 1995 on the proposed site on Deer Island described herein, subject to the following CONDITIONS:

(1) The Petitioners shall inform the Boston Harbor Master, Coast Guard, Boston Pilots Association, all abutters to the Reserved Channel east of the Summer Street Bridge, and other appropriate shipping interests of their construction plans and closely coordinate submarine construction activities in the Reserved Channel and Main Shipping Channel with planned vessel arrivals and departures.

(2) The Petitioners shall fulfill all requirements of the Massachusetts Historical Commission regarding land portions of the approved route.

Stephen Klionsky

Stephen Klionsky
Hearing Officer

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of September 27, 1989 by the members and designees present and voting. Voting for approval of the Tentative Decision: David A. Tibbetts (Acting Secretary of Energy Resources); Mary Ann Walsh (Secretary of Consumer Affairs and Business Regulation); Joellen D'Esti (for Alden S. Raine, Secretary of Economic Affairs); Stephen Roop (for John P. DeVillars, Secretary of Environmental Affairs); Michael Ruane, (Public Electricity Member); Madeline Varitimos (Public Environmental Member); Joseph W. Joyce (Public Labor Member); and Kenneth Astill (Public Engineering Member).

David A Tibbetts

David A. Tibbetts
Chairperson

TABLE 1

ESTIMATED POWER NEEDS OF PLANNED DEER ISLAND WASTEWATER TREATMENT FACILITIES (Megawatts)

Year	Average Load	Essential Peak Load	Peak Load	Expected Shortfall
1990	14.7	23.6	24.4	15.6
1991-92	18.7	25.1	28.9	20.1
1993-94	21.3	36.8	40.6	N/A
1995	24.1	41.4	45.2	39.2
1999	36.8	45.0	64.2	58.2

Notes:

a. The Petitioners defined average load as the power required during conditions of average wastewater flow and peak load as the power required during maximum flow conditions. Essential peak load is the minimum power required during maximum flow conditions to operate vital plant components, as required by the U.S. Environmental Protection Agency. Expected shortfall is the additional electric capacity required to construct and operate the planned wastewater treatment facilities (Exhs. HO-9, BE-8, p. 2-4).

Sources: Exhs. BE-1, p. 1-6, BE-8, pp. 2-2 to 2-4

TABLE 2

ESTIMATED CAPITAL COSTS
(Million $)

Proposed Project Approach and Low Voltage Alternative 2

	Route S-1 115 kV	Route S-2 115 kV
Construction and Permanent Power	$14.8	$17.6

Low Voltage Alternative 1

	Route S-1		Route S-2	
	14 kV	24 kV	14 kV	24 kV
Construction Power Only	$14.0	$12.3	$15.9	$14.0
Construction and Permanent Power	$24.6	$21.5	$27.8	$24.6

Source: Exh. HO-RR-5

TABLE 3

ESTIMATED OPERATING COSTS
1990-1994

Proposed Project Approach

	Route S-1	Route S-2
1990	$12,000	$12,500
1991	25,350	27,000
1992	35,300	37,550
1993	43,200	46,000
1994	44,400	47,400
Total: 1990-94	$160,250	$170,450

Low Voltage Alternatives 1 and 2

	Route S-1		Route S-2	
	14 kV	24 kV	14 kV	24 kV
1990	$52,000	$36,000	$56,550	$39,000
1991	121,400	76,700	129,300	81,700
1992	168,700	106,550	179,700	113,500
1993	187,200	149,000	199,350	158,450
1994	193,100	153,500	205,700	163,400
Total: 1990-94	$722,400	$521,750	$770,600	$556,050

Source: Exh. HO-RR-5

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 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 services 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 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. (See. 5, Chapter 25, G.L. Ter. Ed., as most recently amended by Chapter 485 of the Acts of 1971).

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition)
of Fitchburg Gas and Electric)
Light Company for Approval of)
its Forecast of Gas Resources)
and Requirements)

EFSC 86-11(A)

FINAL DECISION

Frank P. Pozniak
Hearing Officer
September 27, 1989

On the Decision:

Robert M. Graham
Pamela M. Chan

APPEARANCES: Richard Brickley, Jr., Esq.
Brickley, Sears and Sorett
75 Federal Street
Boston, Massachusetts 02250
FOR: Fitchburg Gas and Electric Light Company
Petitioner

TABLE OF CONTENTS

The Energy Facilities Siting Council hereby REJECTS the sendout forecast and the supply plan of the Fitchburg Gas and Electric Light Company.

I. INTRODUCTION

A. Background

The Fitchburg Gas and Electric Light Company ("Fitchburg" or "Company") distributes and sells natural gas in the six communities of Ashby, Fitchburg, Gardner, Lunenburg, Townsend and Westminster in north central Massachusetts. In the split-year 1987-88,[1] the Company had a total of 15,491 customers, comprised of 10,916 residential customers with gas heating, 3,378 residential customers without gas heating, 1,116 firm commercial customers, and 81 firm industrial customers (Exh. HO-SF-22, Tables G-1, G-2, G-3 and G-3(A)).

Fitchburg's forecasts of sendout by customer class for the heating and non-heating seasons are summarized in Table 1.[2] The Company projects an increase in annual normalized firm sendout from 2,465 MMcf in 1989-90 to 2,675 MMcf in 1992-93, representing an annual compound growth rate of 2.8 percent (id., Table G-5).[3]

Fitchburg has access to pipeline gas, liquefied natural

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[1] A split-year runs from November 1 through October 31.

[2] The heating season is defined as the period from November 1 through March 31. The non-heating season extends from April 1 through October 31.

[3] 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), Fitchburg is considered to be a medium-sized gas company.

gas ("LNG"), and propane. The pipeline gas is provided by the Tennessee Gas Pipeline Company ("Tennessee"). The LNG is provided through a contract with Bay State Gas Company ("Bay State") and is stored and vaporized in Westminster (Exhs. HO-RR-8, HO-SP-11, Tables G-14 and G-24). The propane is supplied under a contract with Gas Supply Incorporated ("Gas Supply") and is vaporized at the Company's propane plant in Lunenberg (Exhs. HO-SP-11, Tables G-14 and G-24, HO-SP-15).[4]

Fitchburg has not proposed to construct or acquire any jurisdictional facilities during the forecast period.

B. Procedural History

On December 22, 1986, Fitchburg filed its 1986 sendout forecast and supply plan for the period from 1986-87 through 1990-91. A Notice of Adjudication was issued by the Hearing Officer on February 19, 1987, directing the Company to publish and post the Notice in accordance with 980 CMR 1.03(2). Subsequently, the Company confirmed publication and posting.

On October 2, 1987, the Energy Facilities Siting Council ("Siting Council") staff conducted an evidentiary hearing. The Company presented two witnesses: David W. Graham, senior energy supply analyst; and Michael A. Minkos, assistant vice-president of engineering and energy planning.

Due to the length of time that had elapsed since the evidentiary hearings, the Siting Council staff, on October 28, 1988, requested that Fitchburg provide updated tables of sendout requirements and supply resources for the period from 1988-89 through 1992-93. The Siting Council staff also requested that the Company indicate any changes in its planning standard and forecast methodology for its normal year, design year, design day, and cold snap firm sendout requirements.

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[4] For a complete description of the Company's supply sources and storage facilities, see Section III.C.1, _infra_.

On November 29 and December 15, 1988, the Company provided updated tables of sendout requirements and supply resources (Exhs. HO-SF-22, HO-SP-11).[5] On the same dates, the Company indicated that there are no changes in its planning standard or its forecast methodology for its normal year, design year, design day, and cold snap firm sendout requirements (Exhs. HO-SF-23, HO-SF-24, HO-SP-12 through HO-SP-15). With these responses, the Siting Council is able to review the Company's sendout forecast and supply plan which includes the most recent data, planning standards, and forecast methodologies.

In all, the Siting Council offered 53 exhibits into the record, largely composed of Fitchburg's responses to information and record requests. The Company offered one exhibit into evidence.

5/ The forecast period referenced throughout this decision is the period from 1988-89 through 1992-93.

II. ANALYSIS OF THE SENDOUT FORECAST

A. Standard of Review

The Siting Council is directed by G.L. c. 164, sec. 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. Commonwealth Gas Company, 17 DOMSC 71, 77 (1988) ("1988 ComGas Decision"); Bay State Gas Company, 16 DOMSC 283, 288 (1987) ("1987 Bay State Decision"); Berkshire Gas Company, 16 DOMSC 53, 56 (1987) ("1987 Berkshire Decision"); Boston Gas Company, 16 DOMSC 173, 179 (1987) ("1987 Boston Gas Decision").

In its review of a forecast, the Siting Council determines if a projection method is reasonable according to 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. 1988 ComGas Decision, 17 DOMSC at 77-78; 1987 Bay State Decision, 16 DOMSC at 289; 1987 Berkshire Decision, 16 DOMSC at 56-57; 1987 Boston Gas Decision, 16 DOMSC at 179; Holyoke Gas and Electric Light Department, 15 DOMSC 1, 6 (1986) ("1986 Holyoke Decision"); Westfield Gas and Electric Light Department, 15 DOMSC 67, 72 (1986) ("1986 Westfield Decision"); Bay State Company, 14 DOMSC 143, 150-151 (1986) ("1986 Bay State Decision"); North Attleboro Gas Company, 14 DOMSC 33, 34 (1986).

B. Previous Sendout Forecast Review

In its previous decision, the Siting Council approved Fitchburg's sendout forecast subject to two conditions:[6]

> 2. That the Company shall provide, in its next Supplement, sufficient documentation to support the assumptions in its methodology of deriving customer use factors that these factors will remain constant during the five-year forecast period and that this methodology allows the Company to adjust its projections for known changes in sendout requirements for all classes. Fitchburg shall also provide the supporting documentation justifying its assumption that heating use per degree day does not increase during extremely cold days.
>
> 3. That the Company shall provide in its next filing a narrative description of why or why not the effects of conservation were included, and, if conservation is included, how it is included.

In addition, as Condition Five of its previous decision, the Siting Council ordered Fitchburg to comply with its Decision in <u>Evaluation of Standards and Procedures for Reviewing Sendout Forecasts and Supply Plans of Natural Gas Utilities</u>, 14 DOMSC 95 (1986) ("1986 Gas Generic Order"),[7] and that Decision's implementation in Administrative Bulletin 86-1. <u>Fitchburg Gas and Electric Light Company</u>, 15 DOMSC 39, 65 (1986) ("1986 Fitchburg Decision").

Fitchburg's compliance with these conditions is discussed in Sections II.C.3 through II.D.4, <u>infra</u>.

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[6] The numbers preceding each condition correspond to the numbers assigned in the previous decision.

[7] In the 1986 Gas Generic Order, the Siting Council established procedures which render its review of sendout forecasts and supply plans filed annually by each company more effective in carrying out the Siting Council's statutory mandate by promoting appropriate and reliable sendout forecasting and least-cost, least-environmental impact supply planning.

C. Normal Year and Design Year

1. Weather Data

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, secs. 69H, 69I, and 69J). An important aspect of the Siting Council's analysis of forecasts is its review of a company's weather data. The Siting Council reviews weather data as part of a company's forecast of sendout under normal year and design year, as well as design day, conditions. Further, the Siting Council uses these sendout forecasts as a basis for evaluating the adequacy and cost of a company's supply plan. Therefore, for a company to accurately project sendout requirements and plan supply resources under normal year, design year, and design day conditions over the forecast period, it is necessary for a company to develop a weather database that ensures a reviewable, appropriate, and reliable sendout forecast.

In determining its normal year standard of 6,708 degree days ("DD") (see Section II.C.2, infra), and its design year standard of 7,256 DD (see Section II.C.3, infra), the Company used Worcester-Bedford DD data provided by the Weather Services Corporation for the period from November 1964 through October 1984 (Exh. C-1, Methodology-Degree Day Data; Exh. HO-SF-22, Table DD; Tr. 31). The Company's derivation of its normal year and design year standard raises a number of issues which are addressed below.

a. Range of Weather Data

The Worcester-Bedford weather data used by the Company extends for a 20-year period, from November 1964 through October 1984. The Company did not indicate whether it has a systematic policy for periodically updating this weather database.

For the purposes of this review, the Siting Council finds that the 20-year range of the Worcester-Bedford weather data is appropriate. However, the Siting Council ORDERS Fitchburg in its next forecast filing to develop a systematic methodology for updating its range of weather data.

b. Worcester-Bedford Weather Data

To determine normal year, design year, and design day standards used in forecasting sendout requirements, the Company used Worcester-Bedford weather data (Exh. C-1, Methodology-Degree Day Data). In the past, the Company has used various combinations of Fitchburg and Bedford weather data. See Fitchburg Gas and Electric Light Company, 12 DOMSC 173, 176 (1985) ("1985 Fitchburg Decision"). The Company stated it decided to use Worcester-Bedford weather data because Fitchburg does not have a "weather point", and because the Company wanted a more stabilized weather database (Tr. 31). In support of its change to the Worcester-Bedford weather database, the Company referred to a weather analysis ("1983 weather analysis"), which was included in the Company's 1983 sendout forecast and supply plan, comparing Worcester-Bedford DD and Fitchburg DD over the period from 1964 to 1981 (Exh. HO-RR-2).[8]

In past cases, the Siting Council has found the Company's change to Worcester-Bedford weather data to be appropriate. See 1985 Fitchburg Decision, 12 DOMSC at 176; Fitchburg Gas and Electric Light Company, 10 DOMSC 181, 184 (1984). The Siting Council notes, however, that gas companies are required to file forecasts with the Siting Council that are

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8/ The Siting Council hereby takes administrative notice of the Company's 1983 sendout forecast and supply plan.

based on substantially accurate historical information and reasonable statistical projections. G.L. c. 164, sec. 69J. In determinining whether a statistical method is reasonable, the Siting Council may consider the size of the company, the state of art of forecasting, and the extent to which the forecast methodology requirements of 980 CMR 7.00 are met. See 980 CMR 7.02 (9)(b)(2). Therefore, forecast filings must be reviewed to ensure that such forecast methodologies continue to meet the requirements of the regulations and continue to be appropriate and reliable.

Our reexamination of the 1983 weather analysis upon which the Company made the change to the Worcester-Bedford weather data raises important concerns for the Siting Council at this time. First, the 1983 weather analysis consists solely of overlaid line graphs of weather data from Worcester, Fitchburg, Bedford, and Logan Airport, and does not constitute a weather analysis appropriate for a company the size of Fitchburg. Second, while these line graphs show that, in most years, Worcester DD are greater than Fitchburg DD and Fitchburg DD are greater than Bedford DD, this relationship is not the case for certain years.[9] In fact, in some years, Fitchburg DD were greater than Worcester DD and Bedford DD data. Last, the 1983 weather analysis shows that Fitchburg DD data exists for the years 1964 to 1981, and based on the record, it appears that Fitchburg DD data also exists for the years 1931 to 1964 (Tr. 41). Thus, it appears that a Fitchburg weather database exists for the period 1931 to 1981. It is unclear from the record why the Company does not consider this weather database to be adequate for its sendout forecast calculations.

Despite these concerns regarding the lack of supporting analysis, the Siting Council finds, for the purposes of this

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[9] The weather analysis also shows that Worcester DD, Fitchburg DD, and Bedford DD are all greater than Logan DD for the period from 1964 to 1981.

review, that Fitchburg's use of the Worcester-Bedford weather data to forecast sendout requirements is appropriate and reliable. However, the Siting Council ORDERS Fitchburg in its next forecast filing to provide a detailed analysis demonstrating why its weather database is more appropriate than alternative weather databases for use in forecasting sendout in its service territory.

2. Normal Year Standard

The Company determined its normal year standard of 6,708 DD based on an arithmetic average of 20 years of Worcester-Bedford DD data collected from November 1964 through October 1984 (Exh. HO-SP-22, Table DD).

For the purposes of this review, the Siting Council finds that Fitchburg has established that its methodology for determining the normal year standard is reviewable, appropriate, and reliable for a company the size of Fitchburg.

3. Design Year Standard

The Siting Council Decision in the <u>1986 Gas Generic Order</u>, 14 DOMSC at 97, puts gas companies on notice 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 encountered." 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 recur, and to the effect of the design standard on the reliability of the company's forecast and the cost of its supply plan. <u>1986 Gas Generic Order</u>, 14 DOMSC at 96-97, 104-105. In Condition Five of the Siting Council's most recent Fitchburg decision, the Siting Council reiterated this requirement and again ordered Fitchburg to comply. 1986 Fitchburg Decision, 15 DOMSC at 65.

a. Description

Fitchburg derived its design year standard of 7,256 DD by adding: (1) the DD for a design heating season; and (2) the DD for a normal non-heating season (Exh. HO-SF-3; Exh. C-1, Methodology-Degree Day Data). First, based on the premise that a design year has an occurence probability of once in 50 years, the Company calculated, through a statistical projection using the Worcester-Bedford DD data collected from November 1964 to October 1984, that a design heating season would consist of 5,691 DD (Exh. HO-SF-3). The Company then added this DD figure to the average non-heating season total of 1,565 DD, which was based on the Worcester-Bedford DD data collected from November 1964 to October 1984 (Exh. C-1, Methodology-Degree Day Data, Appendix A, p. 2), to arrive at its design year standard of 7,256 DD.

The Company stated that it selected the occurence probability of once in 50 years "as a starting point" in the calculation of its design year standard (Tr. 38-39). The Company checked the design year standard of 7,256 DD against 50 years of DD data collected from 1931 to 1964 in Fitchburg, and from 1964 to 1981 at the Worcester-Bedford locations (Tr. 40-41), and found that the design year standard had not been met or exceeded during that time period (Tr. 35-37).

b. Analysis

Fitchburg's method of selecting its design year standard raises two serious concerns. The first concern pertains to the Company's use of DD for a normal non-heating season in determining its design year standard. As described above, the Company determined its design year standard by adding DD for a design heating season to the DD for a normal non-heating season. The Company's witness, Mr. Minkos, justified the use of normal non-heating season DD by stating that Fitchburg does "not have a problem meeting non-heating season sendout even in a design year" and that "design conditions for a non-heating season will be met by our pipeline supplies" without the need for using supplemental supplies (Tr. 44). While the Company's assertions may be accurate, they do not constitute an adequate basis for using normal non-heating season DD in determining its design year standard. A design year standard based on design heating and non-heating season DD is the only proper basis for a gas company to forecast design year sendout and plan for adequate supplies to meet those sendout requirements. Therefore, the Siting Council ORDERS Fitchburg in its next forecast filing to develop a design year standard based on design conditions for both the heating and non-heating seasons.

Secondly, the Company has failed to describe and analyze the effect of its design year standard on the reliability of the Company's forecast and the cost of its supply as required by the 1986 Gas Generic Order. Different design year standards are associated with different cost and reliability levels and it is important that gas companies analyze the tradeoffs between cost and reliability in determining an appropriate design year standard. Fitchburg provided no indication of when it would reassess its design year standard in order to determine whether the standard is at the appropriate level of reliability for a company of Fitchburg's size. In addition, the Company has failed to demonstrate that its design year standard does not impose any significant unwarranted supply costs.

Based on the foregoing, the Siting Council finds that Fitchburg has not complied with Condition Five of the 1986 Fitchburg Decision with respect to the design year. The Siting Council also finds that Fitchburg has failed to establish that its methodology for determining its design year standard is appropriate or reliable.

4. Forecast Methodology

a. Description

Based on its normal year standard, Fitchburg forecasted normal year firm sendout requirements for the split-years 1988-1989 through 1992-93 by first setting a load growth target for the Company as a whole and then analyzing the sendout for the historical split-year 1987-88 in order to allocate projected aggregate sendout by heating and non-heating season and by customer class percentages (Exh. C-1, Projected Sendouts-Normal and Design; Exh. HO-SF-22, Tables G-1, G-2, G-3, G-3(A), G-4). The Company then calculated the number of projected customers in each customer class using historical measurements of customer use (Exh. C-1, Projected Sendouts-Normal and Design). To determine design year sendout, Fitchburg followed the same procedure, substituting design year DD for normal year DD (id.).

Fitchburg stated that its goal is to increase normal year sendout by 70 MMcf per year during the forecast period (id.). The Company adopted this goal, which amounts to between 2.5 and three percent per year growth, to match the growth goal of the New England Energy Group (Tr. 15). Fitchburg asserted that this goal is achievable in relation to perceived economic development in its service territory -- e.g., new residential and commercial construction (see Tr. 16, 22-23), and a new industrial park (see Exh. HO-SF-1) -- and that a higher annual percentage growth rate would be unrealistically high (Tr. 17-18).

After selecting its goal for load growth, Fitchburg performed two linear regressions of total firm sendout as a function of degree days, one each for the heating and non-heating seasons, using daily sendout data from its previous year's sendout experience (Exh. C-1, Projected Sendouts, Attachment No. 1). From this calculation, the Company obtained space heating factors (indicating heating use per DD) and baseload factors (indicating non-temperature-sensitive use per day) for the heating and non-heating seasons of the previous year for the Company as a whole (id.).

The Company next multiplied the space heating factors by normal DD and added this product to baseload factors to compute total normalized firm sendout in each of the heating and non-heating seasons of the previous year (id., Projected Sendouts, Attachment No. 2). It then allocated its total annual planned growth of 70 MMcf between the heating and non-heating seasons based on the seasonal sendout percentages for the 1987-88 split year (id., Projected Sendouts-Normal and Design). The Company used this methodology to obtain forecasted normal year sendout for all years of the forecast period (id., Projected Sendouts, Attachment No. 3).

From the season-specific forecasts of total normalized sendout, the Company allocated this sendout to each of the different customer classes according to class percentages which it projected based upon a five-year average of historical class percentages (id., Projected Sendout, Attachment Nos. 1 and 4; Exh. HO-SF-10). The Company indicated that it "made adjustments to certain classes using system knowledge of potential percentage changes among classes" (Exh. HO-SF-10). The Company then determined the number of customers in each customer class for each year of the forecast period by dividing normalized sendout by customer use factors derived from normalized historical data (Exh. C-1, Historical Data and Projected Sendouts; Exh. HO-SF-10).

The Company also provided a forecast of interruptible sendout for the period of split-years 1988-89 through 1992-93 (Exh. HO-SF-22, Table G-4(A)). However, no explanation was given for the methodology used to forecast interruptible sendout (Exh. C-1, Projected Sendouts-Normal and Design).

The results of the forecasts for firm normal and design year sendout requirements are summarized in Table 1.

b. Analysis

In the past, the Siting Council has reviewed Fitchburg's forecast methodology. 1986 Fitchburg Decision, 15 DOMSC at 47-52; 1985 Fitchburg Decision, 12 DOMSC at 176-179. In the 1986 Fitchburg Decision, the Siting Council ordered the Company to comply with Conditions Two and Three, which pertain specifically to key inputs of the Company's forecast methodology, and with Condition Five as well. Here, the Siting Council reviews the Company's compliance with these Conditions and other aspects of the Company's forecast methodology.

i. Previous Conditions

(A) Condition Two

In Condition Two of its previous decision, the Siting Council ordered Fitchburg to: (1) provide documentation supporting the assumption in its methodology that customer use factors will remain constant during the five-year forecast period; (2) justify how its methodology adequately allows the Company to adjust its customer use projections for known changes in sendout requirements for all classes; and (3) provide supporting documentation justifying its assumption that heating use per degree day does not increase during extremely cold days. 1986 Fitchburg Decision, 15 DOMSC at 49-50, 65.

In response to the first part of Condition Two, the Company stated that it "does not believe these factors will remain constant during the forecast period", but that, in examining historical data, the factors "have not changed drastically over the course of the historical period" (Exh. C-1, Conditional Responses). However, the Company did not provide documentation supporting the assumption of constant use factors.

In response to the second part of Condition Two, the Company addressed past changes in its customer use factors, but failed to address future known changes such as those due to new appliance efficiency standards. Rather, Fitchburg continued to assume, without any supporting documentation, that use per customer will remain constant over the forecast period.

In response to the third part of Condition Two, the Company stated that it had performed an analysis of the accuracy of its linear regressions by plotting historical hourly and daily loads versus temperature (Exh. HO-SF-2). From this analysis, the Company indicated that it "determined that the relationship between firm historical load and temperature is a straight line" (id.). The Company did not provide the analysis, but provided daily data on DD and sendout for the 1985-86 split year in support of the analysis (Exh. HO-RR-1).

The Company indicated that this analysis was performed six or seven years ago, and that the methodology was a standard "statistical curve fit" which found that "the curve is generally straight" (Tr. 25, 27-28). The Company asserted that "any type of information provided by the industry indicates that degree days and sendout are a straight line comparison" (Tr. 26).

Based on the record, the Siting Council finds that the Company has not sufficiently demonstrated that heating use per DD does not increase during extremely cold days. The Company did not provide its analysis of DD and sendout, and indicated that such analysis was a handwritten document in a form not presentable to the Siting Council (Tr. 27). For a company the size of Fitchburg, the Siting Council requires a greater degree of sophistication in an analysis of the relationship between DD and sendout. Further, the document the Company provided in support of its analysis fails to demonstrate that heating use per DD does not increase during extremely cold days. The single split-year's data presented by the Company does not include a sufficient number of extremely cold days nor provide adequate representation of potential yearly DD variations to constitute a valid basis for determining the linearity of DD and sendout during extremely cold days.

Based on the foregoing, the Siting Council finds that Fitchburg has failed to comply with Condition Two. The Siting Council ORDERS Fitchburg in its next forecast filing to: (a) present a systematic analysis of the relationship between sendout, DD, and any other factors it determines to be significant; (b) provide supporting documentation justifying the assumption that heating use per degree day does not increase during extremely cold days, using a statistically valid sample of extremely cold days which provides an adequate representation of potential yearly DD variations; and (c) implement the results of this analysis in its forecasting methodology.

(B) Condition Three

In Condition Three of its previous decision, the Siting Council ordered Fitchburg to provide a narrative indicating whether and how the effects of conservation were included in the forecast. 1986 Fitchburg Decision, 15 DOMSC at 65.

In response to this condition, the Company stated that the methodology it uses to develop baseload and space heating factors "would contain any conservation that is currently occuring" (Exh. C-1, Condition Responses).[10] The Company asserted that it "will be looking into methods of quantifying conservation" as it occurs on the system and anticipated it would begin monitoring conservation effects sometime in the forecast period (Exh. C-1, Condition Responses; Tr. 95-97).

The Siting Council finds that Fitchburg has complied with Condition Three.

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[10] In its analysis of Condition Two, supra, the Siting Council found that Fitchburg did not incorporate the effects of conservation into its forecast.

(C) Condition Five

In Condition Five of its last decision, the Siting Council ordered Fitchburg to report on the accuracy of its past forecasts, and to prepare its sendout forecast and supply plan based on a new split-year beginning November 1 and ending October 31. 1986 Fitchburg Decision, 15 DOMSC at 62, 65. In its response, Fitchburg filed Table FA comparing the Company's past forecasts with the actual normalized sendout for those years (Exh. C-1, Revised Table FA). The Company also filed its 1986 sendout forecast and supply plan and later updates based on the new split-year (Exh. C-1; Exhs. HO-SF-22, HO-SP-11).

The Siting Council finds that Fitchburg has complied with those portions of Condition Five pertaining to forecast accuracy and the new split-year.

ii. Other Forecast Methodology Considerations

Fitchburg's selection of a growth target of 70 MMcf annually over the forecast period does not constitute an appropriate forecast methodology. It is inappropriate for a medium-sized gas company such as Fitchburg to judgmentally determine its future load growth; forecasted load growth should be the end-point and not the starting point of a gas company's forecasting process. Moreover, if a company first sets a load growth target, particularly a target based on undocumented assumptions, all results subsequently derived and all supply planning decisions based on those results are inherently suspect. In the instant case, Fitchburg provided no documentation or analysis demonstrating that such load growth would indeed occur throughout the forecast period. Instead, the Company could only provide vague references to new economic development and construction (Exh. HO-SF-1). In addition, Fitchburg's use of a load growth goal raises doubts about the Company's statement that it is committed to "mitigating its expected gas load growth through cost-effective C&LM programs" (Exh. HO-SF-19A, p. 17). Accordingly, the Siting Council finds that Fitchburg has failed to establish that its methodology for forecasting load growth is appropriate.

In addition, the Siting Council notes that the Company failed to justify many of the other assumptions contained in its forecast methodology, including the assumption that new customers will have the same load patterns as existing customers in terms of seasonal and aggregate use and the assumption that forecasted sendout will be allocated among customer classes in similar proportion to existing sendout (Exh. C-1, Projected Sendouts). In the past, the Siting Council has held that a company's filing must be self-contained and supported by sufficient documentation. New England Electric System, 18 DOMSC 295, 327-328, 335, 369 (1989) ("1989 NEES Decision"); 1987 Bay State Decision, 16 DOMSC at 307; Eastern Utilities Associates, 11 DOMSC 61, 65 (1984). See also 980 CMR 7.03(5)(c). The lack of sufficient supporting documentation alone could lead to a rejection of a sendout forecast.

c. Conclusions on Forecast Methodology

The Siting Council has found that Fitchburg has: (1) failed to comply with Condition Two; (2) complied with Condition Three; and (3) complied with those portions of Condition Five pertaining to forecast accuracy and the new split year. The Siting Council also has found that Fitchburg has failed to establish that its methodology for forecasting load growth is appropriate.

The Company's failure to comply with Condition Two, which required Fitchburg to (1) justify its assumption that customer use factors will remain constant over the forecast period, (2) establish that its methodology for forecasting customer use factors is appropriate, and (3) justify its assumption that heating use per degree day does not increase during extremely cold days, represents a serious flaw in the Company's forecast methodology. Of even greater concern is the use of Company-set load growth goals as the basis for determining sendout over the forecast period. This is an inappropriate and unacceptable flaw in Fitchburg's methodological approach.

Accordingly, the Siting Council finds that, on balance, Fitchburg has not established that its forecasting methodologies for the normal year and design year are appropriate. The Siting Council ORDERS Fitchburg in its next forecast filing to reevaluate its existing methodology, data and assumptions for forecasting sendout in light of the serious concerns that have been raised regarding these factors, and to incorporate the results of this reevaluation in its sendout forecast.

The Siting Council also notes that Fitchburg did not incorporate an analysis of the cogeneration market into its forecast. Mr. Minkos indicated that "there is the potential for some cogeneration load" on the Fitchburg system but that the Company "had not yet developed an internal policy as to what size cogeneration that we would like to accept from a gas supply standpoint" (Tr. 18). Mr. Minkos noted that Fitchburg had received several inquiries for service from cogeneration developers planning facilities in the 20-25 megawatt range and that a gas-fired facility of this size would essentially double the size of the Company's annual gas supply requirements (Tr. 19). Mr. Minkos indicated that the Company would probably rather see such cogeneration facilities contract for their own gas supplies, and that perhaps Fitchburg could develop a program wherein it would purchase gas from a cogeneration facility for use as a peaking service and pay the cogenerator the difference between the price of the cogenerator's alternative fuel and its gas supply (id.).

Given the increasing importance of gas-fired cogeneration facilities in the electric power marketplace and the potentially large impact of such facilities on Fitchburg's future gas sendout requirements, the Siting Council ORDERS Fitchburg in its next forecast filing to evaluate the expected impact of cogeneration facilities on its sendout and supply requirements, and to incorporate the results of that assessment in its sendout forecast.

5. Conclusions on the Normal and Design Year

The Siting Council has found that the 20-year range of Worcester-Bedford weather data is appropriate. The Siting Council also has found that Fitchburg's use of Worcester-Bedford weather data to forecast sendout requirements is appropriate and reliable for the purposes of this review.

The Siting Council has found that Fitchburg has established that its methodology for determining the normal year standard is reviewable, appropriate, and reliable. The Siting Council also has found that Fitchburg has not established that its forecast methodology for the normal year is appropriate. Accordingly, the Siting Council finds that Fitchburg's forecast of normal year sendout requirements is neither appropriate nor reliable.

The Siting Council has found that Fitchburg has failed to establish that its methodology for determining the design year standard is appropriate or reliable. The Siting Council also has found that Fitchburg has not established that its forecasting methodology for the design year is appropriate. Accordingly, the Siting Council finds that Fitchburg's forecast of design year sendout requirements is neither appropriate nor reliable.

D. Design Day

1. Weather Data

To determine its design day[11] standard of 70 DD, the Company indicated that it used a Worcester-Bedford database reflecting readings from 1964 to 1986 (Exh. HO-SF-15; Exh. C-1, Methodology-Degree Day Data). The Company's derivation of its design day standard raises two issues: (1) whether the use of the 22-year range of weather data is appropriate; and (2) whether the use of Worcester-Bedford weather data is appropriate and reliable (see Section II.C.1, supra).

For the purposes of this review, the Siting Council finds that using 22 years of Worcester-Bedford weather data is appropriate. The Siting Council herein has found that Fitchburg's use of Worcester-Bedford weather data to forecast normal year and design year sendout is appropriate and reliable (see Section II.C.1.a, supra). This finding similarly applies to the design day sendout forecast.

2. Design Day Standard

The 1986 Generic Gas Order, 14 DOMSC at 96-97, 104-105; and Condition Five of the Siting Council's 1986 Fitchburg Decision, 15 DOMSC at 65, require the Company to include a detailed discussion of how and why it selected its design day standard as well as its design year standard, giving particular attention to the expected frequency of occurence of design conditions and the effect of the design standard on the reliability of the Company's forecast and the cost of its supply plan.

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[11] For the purposes of this review, the Siting Council uses "design day" and "peak day" synonymously.

a. Description

Fitchburg initially indicated that it selected its design day standard of 70 DD because it was the highest recorded DD day during the 22 year period of Worcester-Bedford weather data used by the Company (Exh. HO-SF-15). However, the Company subsequently indicated that over the same 22-year Worcester-Bedford weather database, a 73 DD day actually occurred on December 25, 1980 (Exh. HO-RR-3). In addition, based on a 22-year period of Fitchburg DD data collected from 1965 to 1987, the Company indicated that it actually experienced a 70 DD day on two occasions -- January 8, 1968 and December 25, 1980 (id.).

The Company provided that its design standard has a probability of occurring once in 20 years (Exh. HO-SF-15). Fitchburg asserted that this recurrence probability is valid because a 70 DD day had occurred only once in the 22-year Worcester-Bedford weather database (id.). However, the Company's witness testified that a statistical analysis of actual design day data over this period would probably result in a lower recurrence probability for a 70 DD day, perhaps on the order of once in 30-35 years (Tr. 46).

b. Analysis

Based upon the record, Fitchburg was unable to justify the selection and use of its design day standard of 70 DD. The Fitchburg weather database, which the Company no longer uses, indicated that two 70 DD days actually occurred during the 22-year period analyzed, while the Worcester-Bedford weather database, the weather database the Company currently uses, indicated that 73 DD, and not 70 DD, was the highest DD recorded during the 22-year period analyzed.

In addition, the Company has provided no documentation or analysis in support of its assumption that its design day standard has a recurrence probability of once in 20 years. By the Company's own admission, a statistical calculation of the recurrence probability of its design day standard of 70 DD would likely yield a different recurrence probability than once in 20 years.

Based upon such conflicting and incomplete evidence, the Siting Council finds that Fitchburg has failed to demonstrate that its design day standard is reliable. Further, in light of the Company's failure to provide a valid basis for the selection of its design day standard, the Siting Council finds that the Company has failed to comply with that portion of Condition Five pertaining to the design day standard.

Finally, the Company has failed to describe and analyze the effect of its design day standard on the reliability of the Company's forecast and the cost of its supply as required by the 1986 Gas Generic Order. It is important for gas companies to explicitly analyze the tradeoffs between the various levels of reliability associated with different design day standards and the costs associated with those reliability levels. Fitchburg provided no indication of when it would reassess its design day standard in order to determine whether the standard is at the appropriate level of reliability for a company the size of Fitchburg. As such, the Company has not demonstrated that its design year standard does not impose any significant unwarranted supply costs.

Based on the foregoing, the Siting Council finds that Fitchburg has not established that its methodology for determining its design day standard is appropriate or reliable.

3. Forecast Methodology

Based on its design day standard, Fitchburg forecasted design day sendout requirements for the split-years 1988-89 through 1992-93 by applying its load growth goal for annual firm sendout requirements of between 2.5 and three percent (see Section II.C.4, supra) to its design day load for the previous year and adjusting this number by a "diversity factor" to account for the Company's expectation that non-temperature sensitive load would grow at a somewhat faster rate than temperature sensitive load (Exh. C-1, Peak Day; Exh. HO-SP-11, Table G-23). The Company used the same monthly baseload and heating load factors that were derived for projecting sendout for the normal year and design year (see Section II.C.4, supra).

Fitchburg first established a base design day figure for the previous year by multiplying the heating-season heating load factor by 70 DD and adding that product to the heating-season baseload factor (Exh. C-1, Peak Day). The Company then: (1) divided the sum of the normalized annual load for the previous year and its annual load growth goal for the current year by the normalized annual load for the previous year to determine the annual normalized percentage load growth; (2) multiplied the total normalized design day sendout figure for the previous year by the annual normalized percentage load growth to calculate total normalized design day load growth in terms of MMcf; (3) multiplied the total normalized design day load growth by a "diversity factor" of .85 to calculate an adjusted design day load growth; and (4) added adjusted design day load growth to the design day sendout figure for the previous year to calculate projected design day sendout requirements (id.). The Company repeated this procedure for each year of the forecast period (id.). Fitchburg asserted that its diversity factor is a necessary adjustment because "not all future load growth will be heating load and therefore, probably less temperature sensitive" (Tr. 71).

In its review of the Company's normal year and design year forecasting methodologies, the Siting Council found that Fitchburg failed to establish that its methodology for forecasting total firm sendout for a normal year and design year is appropriate (see Section II.C.4, supra). This finding applies to the Company's forecast methodology for the design day as well. In addition, the Siting Council has found that Fitchburg has failed to establish that its methodology for determining its design day standard is appropriate or reliable.

Finally, the diversity factor of .85 was judgmentally selected by Company management without supporting documentation and analysis. The determination of design day sendout is an important part of a gas company's forecast of resources and requirements. The methodologies used to develop the Company's sendout forecast must be based on reasonable statistical projection methods; assumptions and data used in these methodologies must be fully documented and justified.

Based on the foregoing, the Siting Council finds that Fitchburg has failed to establish that its design day sendout forecast methodology is appropriate.

4. Conclusions on Design Day

The Siting Council has found that the 22-year range of Worcester-Bedford weather data is appropriate. The Siting Council also has found that Fitchburg's use of Worcester-Bedford weather data is appropriate and reliable for the purposes of this review.

The Siting Council has found that Fitchburg has failed to comply with that portion of Condition Five pertaining to the design day standard. The Siting Council also has found that Fitchburg has not established that its methodology for determining its design day standard is appropriate or reliable. Finally, the Siting Council has found that Fitchburg has failed to establish that its design day sendout forecast methodology is appropriate.

Accordingly, the Siting Council finds that, on balance, Fitchburg's forecast of design day sendout requirements is neither appropriate nor reliable.

E. Conclusions on the Sendout Forecast

The Siting Council has found that Fitchburg's forecasts of normal year, design year, and design day sendout requirements are neither appropriate nor reliable.

Accordingly, the Siting Council hereby REJECTS Fitchburg's forecast of sendout requirements.

III. ANALYSIS OF THE SUPPLY PLAN

A. Standard of Review

In keeping with its mandate "to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost," G.L. c. 164, sec. 69H, the Siting Council has traditionally reviewed three dimensions of every utility's supply plan: adequacy, reliability, and cost. 1988 ComGas Decision, 17 DOMSC at 108; 1987 Bay State Decision, 16 DOMSC at 308; 1987 Berkshire Decision, 16 DOMSC at 71; 1987 Boston Gas Decision, 16 DOMSC at 213; Fall River Gas Company, 15 DOMSC 97, 111 (1986) ("1986 Fall River Decision"); 1986 Fitchburg Decision, 15 DOMSC at 54-55; 1986 Holyoke Decision, 15 DOMSC at 27; 1986 Westfield Decision, 15 DOMSC at 72-73; Berkshire Gas Company, 14 DOMSC 107, 128 (1986) ("1986 Berkshire Decision"). While the Siting Council has broadly defined adequacy as the Company's ability to meet projected normal year, design year, peak day, and cold-snap firm sendout requirements with sufficient reserves, the changing character of the gas market and an increasing reliance upon new gas projects that have been subject to delay and cancellation requires the Siting Council to review adequacy both in terms of a company's base plan and its contingency plan.[12] 1988 ComGas Decision, 17 DOMSC at 108; 1987 Bay State Decision, 16 DOMSC at 308; 1987 Berkshire Decision, 16 DOMSC at 71; 1987 Boston Gas Decision, 16 DOMSC at 213.

12/ In the past, the Siting Council has reviewed the adequacy of a gas company's supply plan in the event that certain existing resources become unavailable. Boston Gas Company, 16 DOMSC 1, 36-44 (1986); 1986 Fall River Decision, 15 DOMSC at 115; 1986 Fitchburg Decision, 15 DOMSC at 53; 1986 Bay State Decision, 14 DOMSC at 168; 1986 Berkshire Decision, 14 DOMSC at 127; Essex County Gas Company, 14 DOMSC 189, 201-202 (1986).

Therefore, in order to establish adequacy, a gas company must demonstrate that it has an identified set of resources to meet its projected sendout under a reasonable range of contingencies. If a company cannot establish that it has an identified set of resources to meet sendout requirements under a reasonable range of contingencies, the company must then demonstrate that it has an action plan to meet projected sendout in the event that the identified resources will not be available when expected. 1988 ComGas Decision, 17 DOMSC at 108; 1987 Bay State Decision, 16 DOMSC at 308; 1987 Berkshire Decision, 16 DOMSC at 71; 1987 Boston Gas Decision, 16 DOMSC at 213.

In adopting an expanded definition of adequacy for gas companies, the Siting Council notes that it is no longer necessary to make specific findings regarding the reliability of a company's resource plan. Instead, through review of a company's base plan, under a reasonable range of contingencies and, if necessary, an action plan, the Siting Council has developed an adequacy standard which incorporates concerns regarding the reliability of a company's supply plan. 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.

The Siting Council also reviews whether a utility's supply plan minimizes the cost of energy (that is, whether it ensures least-cost supply), subject to trade-offs with the adequacy, diversity, and environmental impacts of supplies. 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; see 1989 NEES Decision, 18 DOMSC at 337.

The Siting Council recognizes that a company's supply planning process is continuous, and that some balance is always required between the adequacy, cost, and environmental impacts of different supply sources. The Siting Council also recognizes that a company's supply options are affected by conditions existing or expected to exist in its market area and by supplies available in the region. Thus, each company's supply plan will be different, and the Siting Council recognizes the unique factors affecting the particular company under review. The Siting Council reviews each company's basis for selecting a supply alternative, or the company's decisionmaking process which led it to select that supply alternative, to ensure that the company's decisions are based on projections founded on accurate historical information and sound projection methods. 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.

B. Previous Supply Plan Review

In the 1986 Fitchburg Decision, 15 DOMSC at 65, the Siting Council approved Fitchburg's supply plan subject to the two following conditions:[13]

> 1. That the Company shall include in its next Supplement the results of its marginal cost study and a discussion of the status of development of conservation and load management programs. The discussion shall include a comparison of the cost-effectiveness of relying upon conserved gas as a source of supply versus obtaining other gas supplies to meet new load requirements, and a justification of the method of comparison.
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> .....
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> 4. That the Company shall include in its next filing a contingency plan for LNG, including: the status of the Distrigas [Corporation] and DOMAC [Distrigas of Massachusetts Corporation] federal government applications; the impact of [Federal Energy Regulatory Commission ("FERC")] Order No. 380 on DOMAC's ability to supply Bay State [Gas Company] with LNG and the resultant capability of Bay State to supply Fitchburg

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[13] The numbers preceding each condition correspond to the numbers assigned in the previous decision.

> with LNG; and identification of other potential suppliers of LNG, and possible terms of delivery.[14]

In addition, as Condition Five of that decision, the Siting Council ordered Fitchburg to comply with the Siting Council's Decision in the 1986 Gas Generic Order and that Decision's implementation in Administrative Bulletin 86-1.

Fitchburg's compliance with these conditions is discussed in Section III.C.1.b.ii, and Section III.C.2, _infra_.

C. Adequacy of Supply

1. Evaluation of Base Case Resources

In order to determine whether a gas company's base case resource plan is adequate, the Siting Council must first determine if that company can reasonably rely on each resource in its base case plan to meet its sendout requirements during the forecast period.[15]

a. Pipeline Gas and Storage Services

i. Existing Deliveries and Services

Fitchburg receives deliveries of pipeline supplies and storage gas from Tennessee, Boundary Gas Incorporated ("Boundary"), Penn-York Energy Corporation ("Penn-York"), and Consolidated Gas Supply Corporation ("Consolidated") (Exhs.

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[14] Distrigas Corporation is the parent company of DOMAC, and is the major importer of LNG supplies to the northeastern United States. DOMAC is a major distributor of imported LNG to local distribution companies in the northeastern United States.

[15] Fitchburg does not include conservation and load management in its base case resource plan. See Section III.C.2, _infra_, for a description and analysis of the Company's conservation and load management activities.

HO-SP-11, Table G-24, HO-RR-6, HO-RR-9; Exh. C-1, Supplements). Tennessee provides Fitchburg with firm pipeline deliveries of gas under rate schedule CD-6 (Exh. HO-SP-11, Tables G-22N, G-22D, G-23). The maximum daily quantity ("MDQ") of such deliveries to Fitchburg under its contract with Tennessee is 7.7 MMcf (id., Table G-24). The annual volumetric limitation ("AVL") under the same contract is 2,805 MMcf (id.).

Fitchburg also receives firm pipeline deliveries of gas from Boundary (Exhs. HO-RR-6, HO-SP-12). Fitchburg began to receive these firm volumes from Boundary on January 15, 1988 (Exh. HO-SP-12), with firm transportation provided by Tennessee (Exh. C-1, p. 2; Exh. HO-RR-6). The MDQ of pipeline deliveries to Fitchburg under the Boundary contract is .5 MMcf, with an AVL of 183.5 MMcf (Exh. HO-SP-11, Table G-24).

In addition, Fitchburg has agreements with Penn-York and Consolidated for underground storage services under rate schedules GSS and SS-1, respectively (Exh. HO-RR-9; Exh. C-1, Supplements). Pursuant to its contract with Penn-York, Fitchburg receives a MDQ of 2.8 MMcf of underground storage gas, with an AVL of 309 MMcf (Exh. HO-SP-11, Table G-24). The MDQ of underground storage gas Fitchburg receives under its contract with Consolidated is .446 MMcf, with an AVL of 51.3 MMcf (id.). Tennessee provides firm transportation of the gas stored at the Consolidated and Penn-York facilities (Exh. C-1, p. 2).

The Siting Council finds that for base case planning purposes Fitchburg can reasonably rely on its full contractual volumes from Tennessee, Boundary, Penn-York, and Consolidated throughout the forecast period.

ii. Planned Pipeline Deliveries

Fitchburg's supply plan indicated that new pipeline services would begin during the forecast period. Fitchburg stated that it is a participant in Tennessee's NOREX Project (Exh. HO-SP-1). Gas volumes from the NOREX Project would increase daily maximum firm pipeline deliveries from Tennessee under rate schedule CD-6 from 7.7 MMcf to 10.25 MMcf beginning in the 1989-90 heating season, and increase the AVL by 200 MMcf beginning in the same heating season (Exhs. HO-SP-1, HO-SP-11, Tables G-22D and G-23; Tr. 125-126). Fitchburg indicated that it anticipates that it will begin to receive its NOREX volumes on November 1, 1989 (Exh. HO-SP-1).

The Siting Council finds that for base case planning purposes Fitchburg can reasonably rely on the NOREX Project beginning service on November 1, 1989.[16]

b. Liquefied Natural Gas

i. Supplies and Facilities

Fitchburg owns an LNG facility in Westminster with a storage capacity of 4.17 MMcf and a vaporization capacity of 7.2 MMcf/day (Exh. HO-SP-11, Table G-14). This facility has no liquefaction capability (Tr. 134).

Fitchburg presently receives its total supply of LNG from Bay State (Exh. HO-SP-11, Table G-24; Exh. HO-RR-8). Most of the Bay State LNG provided to Fitchburg originates with DOMAC (Tr. 121). The remainder is produced by Bay State using Bay State's own liquefaction facilities. The Company's contract with Bay State provides for 120 MMcf in firm volumes and an optional 40 MMcf in firm volumes, all delivered during

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16/ The Siting Council evaluates the contingency of a one-year delay in the NOREX Project in its analysis of the adequacy of the Company's supply plan. See Sections III.C.3 and 4, *infra*.

the heating season (Exhs. HO-SP-11, Table G-24, HO-RR-8).[17] Pursuant to the contract, the Company can obtain a daily maximum of 5.6 MMcf (Exh. HO-RR-8).

The Siting Council finds that for base case planning purposes Fitchburg can reasonably rely on a dispatch capability for its LNG facility of 7.2 MMcf/day throughout the forecast period.

ii. Condition Four

(A) Description

As stated in Section III.B. above, in Condition Four of the 1986 Fitchburg Decision the Company was ordered to include in its contingency plan for LNG: (1) the status of the Distrigas and DOMAC federal government applications; (2) the impact of FERC Order No. 380 on DOMAC's ability to supply Bay State with LNG; (3) the resultant capability of Bay State to supply Fitchburg with LNG; and (4) the identification of other potential suppliers of LNG.

In response to this condition, Fitchburg stated that as its pipeline supplies increase, its dependence on LNG will be reduced (Exh. C-1, Condition Responses). While the Company noted that Bay State has similarly reduced its dependence on LNG, Fitchburg asserted that Bay State had "assured Fitchburg that its current liquefaction and storage capacity is sufficient to meet Fitchburg's contractual requirements" (id.). Fitchburg initially asserted that it intended to purchase a small amount of LNG from Hopkinton LNG Corporation ("Hopkinton LNG") as it had done in the past (id.). However,

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[17] Fitchburg has an option to receive firm volumes of 10 MMcf, 20 MMcf, and 10 MMcf during January, February, and March, respectively (Exh. HO-RR-8). To obtain any of these volumes, Fitchburg must notify Bay State in writing at least ten days before the beginning of that month (id.).

the Company's witness, Mr. Minkos, subsequently indicated that the Company had chosen not to renew its contract with Hopkinton LNG (Tr. 121). Fitchburg justified this decision by stating that it had experienced no difficulty obtaining supplies of LNG from Bay State during the winter of 1986-87 (id.).

(B) Analysis

In its response to the first and second parts of Condition Four, Fitchburg did not provide any information on the status of any Distrigas or DOMAC federal applications, nor did Fitchburg describe the impact of FERC Order 380 on DOMAC's ability to supply Bay State with LNG. In regard to the fourth part of this condition, Fitchburg did not identify any other sources of LNG supplies other than Hopkinton LNG with whom Fitchburg chose not to renew its contract.

With respect to the third part of Condition Four, the Company indicated that Bay State has assured Fitchburg that its current liquefaction and storage capacity is sufficient to meet Fitchburg's contractual requirements. However, Fitchburg failed to provide documentation and analysis in support of this assertion which would demonstrate that Fitchburg will be provided with its contractual requirements from Bay State's liquefaction and storage capacity, particularly under design conditions. Accordingly, the Siting Council finds that the Company failed to provide sufficient evidence demonstrating Bay State's capability of supplying Fitchburg with LNG from its liquefaction and storage capacity.

Based on the foregoing, the Siting Council finds that Fitchburg failed to provide an adequate contingency plan for LNG as required by Condition Four. Accordingly, the Siting Council finds that Fitchburg failed to comply with Condition Four.

The Siting Council recognizes, however, that the viability of DOMAC LNG supplies has changed since the 1986 Fitchburg Decision. At that time, Distrigas had filed for bankruptcy, thereby creating uncertainty about the reliability of DOMAC as a source of supply. 1986 Fitchburg Decision, 15 DOMSC at 53. In December 1988, Distrigas and DOMAC received conditional FERC approval to restructure LNG sales and storage services. Distrigas also reached a settlement with its Algerian supplier, and now has resumed purchasing LNG from this supplier under an amended contract.[18]

Although the circumstances regarding the viability of Distrigas supplies have changed, it remains important to assess the reliability of Bay State's LNG sales to Fitchburg.

Therefore, the Siting Council ORDERS Fitchburg in its next forecast filing to provide: (a) all contracts signed by DOMAC and Bay State for LNG deliveries during the forecast period; and (b) a description and analysis of Fitchburg's capability, particularly under design conditions, to obtain LNG supplies from Bay State in the event of a DOMAC LNG supply disruption.[19]

c. Propane

Fitchburg owns a propane facility in Lunenberg which has a storage capacity of 30.4 MMcf and vaporization capacity of 7.2 MMcf/day (Exh. HO-SP-11, Table G-14). The Company indicated that it plans to increase the vaporization capacity at this propane facility for the 1989-90 heating season and the

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18/ See FERC's Decision in Docket CP-88-587, dated December 16, 1988. The Siting Council hereby takes administrative notice of this Decision.

19/ The Siting Council evaluates the contingency of a one-year disruption in Bay State LNG supplies in its analysis of the adequacy of the Company's supply plan. See Section III.C.3 and 4, infra.

remaining years of the forecast period to 12 MMcf/day (Exh. HO-1).[20]

The Company contracts annually with Gas Supply, Inc. for its firm liquid propane supply (Exhs. HO-SP-11, Table G-24, HO-SP-15, HO-RR-7; Tr. 114). The current contract with Gas Supply, Inc. provides for 500,000 gallons (55 MMcf) of propane delivered during the heating season (Exh. HO-SP-15). The MDQ is 4.8 MMcf (Exh. HO-SP-11, Table G-24).

The Siting Council finds that Fitchburg can reasonably rely for base case planning purposes on a dispatch capability for its propane facility of 7.2 MMcf/day throughout the forecast period.

2. Conservation and Load Management

In 1986, the Massachusetts legislature amended the Siting Council's statute to require the Siting Council to approve a company's long-range forecast only if the Siting Council determines that a utility company has demonstrated that its forecast "include[s] an adequate consideration of conservation and load management." G.L. c. 164, sec. 69J. In fulfilling this statutory mandate, the Siting Council, prior to its order in the 1988 ComGas Decision, 17 DOMSC at 71, reviewed gas conservation and load management ("C&LM") efforts in terms of cost minimization issues. In that case, however, the Siting Council expanded its review to determine whether a gas company can demonstrate that it has reasonably considered C&LM programs as resource options to help ensure that it has adequate supplies to meet projected sendout requirements. 1988 ComGas Decision, 17 DOMSC at 123-126.

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[20] Pursuant to 980 CMR 7.07(8), this planned increase in propane vaporization capacity does not constitute a construction of facilities requiring approval by the Siting Council.

a. Description

i. Conservation and Load Management Plan

Fitchburg presented a detailed Conservation and Load Management Plan ("C&LM Plan") in which it outlines its objectives for gas and electric C&LM programs, and a framework for identifying, implementing, and evaluating gas and electric C&LM programs (Exh. HO-SF-19A).[21] The Company's objectives include: (1) the consideration of all supply and C&LM options to provide its customers with reliable service at least cost; (2) the use of the marginal cost of gas as a basis forevaluating the cost-effectiveness of all gas supply and C&LM options to satisfy customer needs; and (3) the inclusion of non-price factors, such as risk, to maximize the expected net benefits of any C&LM program or supply option to the Company's customers (id., p. 2).

Fitchburg's framework for C&LM planning includes the following elements:

1. Identification of the resources required to satisfy expected customer demands with adequate reliability by defining and estimating the marginal costs of a base resource plan to meet forecast customer needs. Such a plan will provide the basis against which all supply and C&LM options should be measured;
2. Identification of potential C&LM candidate programs, selection of those C&LM programs that best satisfy the plan objectives, and design of such C&LM programs to maximize expected economic benefits to the Company's customers;
3. Implementation of the C&LM programs in accordance with the plan objectives to maximize program effectiveness and minimize program costs; and

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[21] As a combined gas and electric utility, Fitchburg has set forth C&LM programs to conserve electricity as well as gas. The gas-related C&LM programs described herein are generally the gas portion of broader programs that are also available to Fitchburg's electric customers.

4. Institution of a measurement and evaluation process that provides continuous cost-benefit information and documents C&LM program effectiveness and satisfaction with C&LM Plan objectives. (id., p. 5).

The Company further stated that it intends to integrate C&LM planning with its overall planning process, and reach full-scale C&LM program implementation as quickly as possible (id., p. 1). Fitchburg also stated that it is committed to "mitigating its expected gas load growth through cost-effective C&LM programs" (id., p. 17).

Fitchburg indicated that it will employ a marginal cost analysis to determine the cost-effectiveness of gas C&LM programs (id.). In its C&LM Plan, the Company stated that "it is presently working on, but has not completed, an analysis of the marginal costs of gas supply as part of its gas rate design efforts" (id.). The Siting Council initially ordered Fitchburg in the 1985 Fitchburg Decision, 15 DOMSC at 195, to provide the results of its marginal cost study in its next forecast filing. Fitchburg failed to provide the results of a marginal cost study in its next filing as required, stating that it was unable to complete the study due to severe financial problems during the first three quarters of 1985. 1986 Fitchburg Decision, 15 DOMSC at 45. In Condition One of the 1986 Fitchburg Decision, the Siting Council once again ordered Fitchburg to provide the results of its marginal cost study in its next filing (Id., at 65). In the instant proceeding, the Company first indicated that the marginal cost analysis would be completed by November 1, 1987, and would be incorporated into the Company's gas C&LM planning efforts (Exh. HO-SF-19A, p. 17). The Company subsequently changed the completion date to December 1987, but then indicated that the analysis would not be completed by that date, and set a new completion date for the first quarter of 1990 (Exhs. HO-SP-6, HO-SP-13).

ii. Current C&LM Programs

Fitchburg stated that it is currently participating in four gas-related C&LM projects: (1) the Energy Conservation Services Program; (2) the Energy Advisor Services Program; (3) the Massachusetts Collaborative C&LM Design Effort; and (4) general C&LM projects (Exh. HO-SF-26).

First, under the Energy Conservation Services Program, the Company, in cooperation with F.A.C.E. (Fundamental Action to Conserve Energy), a local energy conservation organization in Fitchburg's service territory, performed 500 residential audits in 1986-87 and 609 audits in 1987-88 (Exhs. HO-SF-18, HO-SF-25). The Company indicated that it plans to perform 500 additional residential audits in 1988-89 (Exh. HO-SF-25). For 1988-89, Fitchburg indicated that it strengthened the direct materials installation component of the Energy Conservation Services Program, and established a prioritization system forinstalling energy conservation equipment (Exh. HO-SF-26). This priority package currently includes water heater wraps, pipe insulation, and low-flow showerheads (id.). Fitchburg projects that it will install this equipment in 281 units in 1988-89, resulting in a savings of .843 MMcf annually (id.).

Second, Fitchburg also has undertaken a coordinated effort with the Massachusetts Executive Office of Energy Resources ("EOER") to promote EOER's Energy Advisor Service Program to all of Fitchburg's commercial and industrial gas customers (id.). The program identifies both potential gas and electric C&LM measures (id.). As part of this program, Fitchburg provides half of the cost of the initial energy audit (id.). Fitchburg asserted that this program has been successful, and stated that 50 percent of eligible customers have participated, although it could not quantify resultant customer savings (id.).

Third, Fitchburg is a participant in the Massachusetts Collaborative C&LM Design Effort (id.). The Company stated that while this project is focused primarily on electricity

C&LM design, generic policy issues, which in the future will impact gas C&LM programs, are being discussed (id.).

Finally, Fitchburg indicated that it is increasing its involvement in general C&LM projects (id.). In particular, Fitchburg is presently investigating the feasibility of offering a load management incentive to its dual fuel customers (id.). The Company stated that to date it has focused primarily on electricity C&LM, and that this experience will benefit its future gas C&LM efforts through an increased understanding of program design and evaluation concepts (id.).

b. Analysis

i. Condition One

In Condition One of its previous decision, the Siting Council required Fitchburg to include in its next forecast filing the results of its marginal gas cost study and a discussion of the status of its C&LM programs. The Siting Council further required that the discussion include a comparison of the cost-effectiveness of conserved gas as a supply versus obtaining other gas supplies to meet load requirements and a justification of the method of comparison.

To date, Fitchburg still has not completed its marginal cost study, and as a result, has not provided the results of this study to the Siting Council. By Fitchburg's own admission, the results of this study are required to determine the cost-effectiveness of gas C&LM programs relative to available supply options.[22] Thus, Fitchburg has not analyzed

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[22] The Massachusetts Department of Public Utilities has required all utilities to use long-run avoided costs as the basis for determining the cost-effectiveness of C&LM and other resource options. See Boston Gas Company, D.P.U. 88-67 (1988); Fitchburg Gas and Electric Light Company, D.P.U. 84-145-A (1985). The Siting Council hereby takes administrative notice of these two decisions.

the cost-effectiveness of gas C&LM programs, and has not specified a definite time frame for completing such analysis. While Fitchburg discussed the status of its gas C&LM programs and demonstrated that it has made progress in planning for such C&LM programs, the Company has not made substantial progress in implementing C&LM programs and has not compared and analyzed the cost-effectiveness of C&LM programs versus new supply options. (see Section III.D, infra).

Accordingly, the Siting Council finds that Fitchburg has failed to comply with Condition One. The Siting Council ORDERS Fitchburg in its next forecast filing to: (a) provide the results of a marginal cost study or studies that are consistent with the standards of the Massachusetts Department of Public Utilities for determining the cost-effectiveness of C&LM and other resource options; (b) provide an update on the status of its gas C&LM programs; (c) perform a detailed analysis of the cost-effectiveness of various gas C&LM programs relative to available options for new supply, and justify the method of comparison; and (d) describe in detail how the results of its cost-effectiveness analysis of gas C&LM programs are or will be integrated into the Company's supply planning process.[23]

ii. C&LM as a Resource Option

Based on the record, Fitchburg's implementation of gas C&LM programs is still limited relative to the size of existing and planned new supplies. Fitchburg also has failed to focus sufficiently on C&LM monitoring efforts and must improve its ability to estimate the gas saved from its gas C&LM programs. Further, definite conclusions on the cost-effectiveness of the Company's existing gas C&LM programs or potential future gas C&LM programs cannot be made by the Company at this time

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23/ See Section III.D.1, infra, for a discussion of the role of C&LM in Fitchburg's least-cost planning process.

because the Company has failed to complete its marginal cost study.

At the same time, however, the Siting Council notes that the Company has made significant progress in defining its objectives for C&LM programs and establishing a framework for C&LM planning. In addition, the Company has begun to quantify the impact of one of its gas C&LM programs, the Energy Conservation Services Program. The Siting Council recognizes that the incorporation of C&LM in gas utilities' supply planning is still evolving, and that Fitchburg's C&LM Plan and current C&LM programs are positive indicators of Fitchburg's intention to reasonably consider C&LM programs as resource options.

The Siting Council expects Fitchburg to make further efforts toward identifying and measuring the savings of existing and potential cost-effective C&LM programs. There is no apparent reason for Fitchburg to continue to exclude C&LM from its base case resource plan. Thus, the Siting Council ORDERS Fitchburg in its next filing to: (a) quantify the savings of its existing and planned C&LM programs over the forecast period; and (b) to incorporate these estimates into its base case resource plan and its analyses of adequacy for normal and design conditions.

Based on the foregoing, the Siting Council makes no finding here regarding whether Fitchburg's supply planning process included an adequate consideration of C&LM.

3. Normal and Design Year Adequacy

In normal and design year planning, Fitchburg must have adequate supplies to meet several types of requirements. Fitchburg's primary service obligation is to meet the requirements of its firm customers. 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, Fitchburg also supplies gas to its interruptible customers.

The Company's base case normal year supply plan indicates that the Company has adequate supplies to meet forecasted normal year requirements throughout the forecast period (Exh. HO-SP-11, Table G-22D). Accordingly, the Siting Council finds that Fitchburg has established that it has adequate resources to meet forecasted firm normal year sendout requirements throughout the forecast period.

Base case and contingency analyses of Fitchburg's design year supply plan are set forth below.

a. Base Case Analysis

Fitchburg's forecasted design year firm sendout requirements and base case supply plan are summarized in Tables 2 and 3 for the heating and non-heating seasons respectively. The base case supply plan includes gas supply from the NOREX Project beginning in 1989-1990 (Exh. HO-SP-11, Table G-22D). The base case supply plan does not include storage volumes from Fitchburg's propane facility in 1989-90 and 1991-92 or any forecasted gas savings from Fitchburg's C&LM programs (id.).[24]

In all years of the forecast period, the Company's base case supply plan would meet its forecasted design year requirements. Accordingly, the Siting Council finds that Fitchburg has established that its base case supply plan is adequate to meet the Company's forecasted firm design year sendout requirements in all years of the forecast period.

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[24] Although Fitchburg does not include propane storage volumes in its base case supply plan for the years listed, these volumes would still be available to the Company if the Company should require them.

b. Contingency Analysis

i. One-Year Delay in NOREX Project

Fitchburg stated that the expected in-service date for the Tennessee NOREX Project is November 1, 1989. If the NOREX Project is delayed by one year, and if all other resources in the base case supply plan remain available to the Company, Fitchburg would experience a resource deficiency in 1989-90 of 22 MMcf (1.2 percent) (see Table 4). In the event of such a delay, an action plan involving the use of some portion of its 30.4 MMcf of propane storage capacity would meet this resource deficiency (Exhs. HO-RR-8, HO-SP-11, Table G-14).[25]

Accordingly, the Siting Council finds that Fitchburg can meet the resource deficiencies in 1989-90 and has adequate resources to meet forecasted firm design year sendout requirements in the event of a one-year delay in the NOREX Project.

ii. Disruption in Bay State LNG Deliveries

Fitchburg contracts for firm and optional LNG purchases from Bay State. Bay State purchases LNG from DOMAC, and also liquefies LNG from its pipeline and storage supplies. Fitchburg relies on Bay State LNG to meet between 6.6 and 8.1 percent of its design year firm sendout requirements over the forecast period (Exh. HO-SP-11, Table G-22D).

A comparison of forecasted firm sendout requirements and resources for a design year in the event that Bay State LNG is not available to Fitchburg in 1989-90 is summarized in Table 4. If all other resources in the base case supply plan remain

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[25] The Siting Council assumes that Fitchburg would obtain spot propane purchases to fill its propane storage facility before the 1989-90 heating season.

available, Fitchburg would not experience a resource deficiency in any year of the forecast period.

Accordingly, the Siting Council finds that Fitchburg has established that it has adequate resources to meet forecasted firm design year requirements in all years of the forecast period in the event that LNG supplies are not available from Bay State in 1989-90.

c. Conclusions on Design Year Adequacy

The Siting Council has found that Fitchburg: (1) has established that its base case supply plan is adequate to meet the Company's forecasted firm design year sendout requirements in all years of the forecast period; (2) can meet the resource deficiencies in 1989-90 and has adequate resources to meet forecasted firm design year sendout in the event of a one-year delay in the NOREX Project; and (3) has established that it has adequate resources to meet forecasted firm design year sendout requirements in all years of the forecast period in the event that LNG supplies are not available from Bay State in 1989-90.

Accordingly, the Siting Council finds that Fitchburg has established that it has adequate resources to meet its forecasted firm design year sendout requirements throughout the forecast period.

4. Design Day Adequacy

Fitchburg 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 peak day.

a. Base Case Analysis

Fitchburg's forecasted firm design day sendout requirements and base case supply plan is summarized in Table 5. The base case supply plan includes the gas supply from the NOREX Project beginning in 1989-1990 (Exh. HO-SP-11, Table G-22D). The base case supply plan does not include the planned expansion of the Company's propane vaporization capacity or any forecasted gas savings from its C&LM programs (id.). In all years of the forecast period, the Company's base case supply plan would meet forecasted firm design day requirements.

Accordingly, the Siting Council finds that Fitchburg has established that its base case supply plan is adequate to meet forecasted firm design day sendout requirements in all years of the forecast period.

b. Contingency Analysis

i. One-Year Delay in NOREX Project

Fitchburg stated that the expected in-service date for the NOREX Project is November 1, 1989. If all other resources in the base case supply plan remain available to the Company, Fitchburg would not realize a resource deficiency in any year of the forecast period in the event of a one-year delay in the NOREX Project (see Table 6).

Accordingly, the Siting Council finds that Fitchburg has established that it has adequate resources to meet its forecasted firm design day requirements in all years of the forecast period in the event of a one-year delay in the NOREX Project.

ii. Disruption in Bay State LNG Deliveries

Fitchburg relies on Bay State LNG to meet between 31.4 and 33.5 percent of its firm design day requirements over the forecast period (Exh. HO-SP-11, Table G-23). A comparison of firm design day sendout requirements and resources in the event that Bay State LNG is not available to Fitchburg in 1989-90 is summarized in Table 6. If all other resources in the base case supply plan remain available to the Company, Fitchburg would experience a resource deficiency of 0.3 MMcf (1.3 percent) in 1989-90. In the event of the unavailability of Bay State LNG in 1989-1990, an action plan involving the utilization of the Company's planned propane vaporization capacity increase to 12 MMcf/day in 1989-90 would meet this resource deficiency (Exh. HO-1).

Accordingly, for the purposes of this review, the Siting Council finds that Fitchburg can meet the resource deficiencies in 1989-90 and has adequate resources to meet its firm design day sendout requirements in all other years of the forecast in the event that LNG supplies are not available from Bay State in 1989-90.

c. Conclusions on Design Day Adequacy

The Siting Council has found that Fitchburg: (1) has established that its base case supply plan is adequate to meet forecasted firm design day sendout requirements in all years of the forecast period; (2) has established that it has adequate resources to meet its forecasted firm design day sendout requirements in all years of the forecast period in the event of a one-year delay in the NOREX Project; and (3) can meet the resource deficiencies in 1989-90 and has adequate resources to meet its firm design day sendout requirements in all other years of the forecast in the event that LNG supplies are not available from Bay State in 1989-90.

Accordingly, the Siting Council finds that Fitchburg has established that it has adequate resources to meet its forecasted firm design day sendout requirements throughout the forecast period.

5. Cold Snap Adequacy

The Siting Council has defined a cold snap as a prolonged series of days at or near design conditions. 1986 Fitchburg Decision, 15 DOMSC at 58. 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. 1988 ComGas Decision, 17 DOMSC at 137; 1987 Berkshire Decision, 16 DOMSC at 79; 1986 Fitchburg Decision, 15 DOMSC at 58, 61.

Fitchburg presented a cold snap analysis based on a sendout forecasted for a total of 600 degree days over a ten day period (Exhs. HO-SP-8, HO-SP-14). This analysis was based on the Company's historic maximum cold spell for a ten day period using 21 years of Worcestor-Bedford weather data (Exh. HO-SP-10). The Company used 1985-86 customer baseload and space heating factors to forecast a required sendout of 175.13 MMcf for the cold snap period (Exhs. HO-SP-8, HO-SP-14).

Fitchburg did not specify in which month the cold snap used in its analysis would occur. The month of occurrence is of critical importance because the resources available to the Company to meet its projected cold snap sendout requirements vary from month to month over the heating season because of monthly variations in the availability of Bay State LNG volumes, and, to a lesser degree, because of possible variations in the amount of propane in the Company's propane storage facility. Since February was the month when the Company's historic maximum cold spell actually occurred, the Siting Council selects February as the base month for reviewing Fitchburg's cold snap analysis.

Of the resources available to Fitchburg to meet cold snap requirements in February, approximately 65.5 percent are firm pipeline deliveries: Tennessee CD-6 and Boundary (46.9 percent of peak day resources available); and underground storage from Consolidated and Penn York (18.6 percent) (Exh. HO-SP-8). Fitchburg indicated that it plans to meet the remaining 34.5 percent of its cold snap requirements with its supplemental fuels, propane and LNG (id.).

In February, Fitchburg receives 30 MMcf of firm Bay State LNG, and has an option to receive an additional 20 MMcf of firm volumes (Exh. HO-RR-8). The Company plans to use approximately 43.2 MMcf (or 86 percent) of its Bay State LNG available in February to meet its cold snap sendout requirements, and 15.5 MMcf (or approximately 50 percent) of the Company's on-site propane storage capacity (Exh. HO-SP-8). In the event that Fitchburg does not elect to purchase its optional LNG volumes in February and experiences the aforementioned cold snap, the Company could still meet its cold snap requirements with additional amounts of propane. Under its contract for firm propane supply, the Company is normally entitled to receive three truckloads of propane in a 24-hour period amounting to approximately 2.5 MMcf (Tr. 116-117). At this rate, the Company could nearly meet its additional propane needs of approximately 28.6 MMcf over the 10-day cold snap period. In addition, the Company indicated that it has been able to get more than three truckloads of propane in a 24-hour period when it has needed additional amounts of propane (id.). Further, the Company's propane storage capacity of 30.4 MMcf gives Fitchburg approximately four days of on-site propane storage. Thus, a combination of this propane supply and transportation capability would allow Fitchburg to meet its firm sendout requirments during a cold snap in the event that the Company does not take its optional Bay State LNG volumes in February.[26]

Accordingly, the Siting Council finds that Fitchburg has established that it has adequate resources to meet its forecasted firm sendout requirements under cold snap conditions in February given 1985-86 baseload and space heating factors. However, as a result of monthly variations in the resources available to Fitchburg over the heating season, it is necessary for the Company to demonstrate its ability to meet a cold snap at any time period during the heating season. Therefore, the Siting Council ORDERS Fitchburg in its next forecast filing to provide a cold snap analysis which (a) identifies the month or months of the heating season in which a cold snap reasonably can be expected to occur, and (b) demonstrates that Fitchburg has adequate resources to meet cold snap sendout requirements for each month identified.

6. Conclusions on the Adequacy of Supply

The Siting Council has found that Fitchburg has established that: (1) it has adequate resources to meet its forecasted firm normal year, design year, and design day sendout requirements throughout the forecast period; and (2) it has adequate resources to meet its forecasted firm sendout requirements under cold snap conditions in February throughout the forecast period.

Accordingly, the Siting Council finds that Fitchburg has established that it has adequate resources to meet its firm sendout requirements throughout the forecast period.

26/ The cold snap analysis presented by Fitchburg does not include the additional pipeline volumes that it expects to receive from the NOREX Project beginning in November, 1989 (Exhs. HO-SP-8, HO-SP-11, Table G-23). If NOREX were to be included, the Company presumably would reduce its requirements for supplemental supplies during the cold snap.

D. Least-Cost Supply

1. Comparison of Alternatives on an Equal Footing

In 1986, the Massachusetts legislature amended G.L. Chapter 164, Section 69 to allow the Siting Council to approve a company's long-range forecast only if the Siting Council determines that a company has demonstrated that its forecast "include[s] an adequate consideration of conservation and load management." G.L. c. 164, sec. 69J. To ensure that a company's supply planning process minimizes costs, the Siting Council also evaluates whether a company's supply planning process adequately considers alternative resource additions, including C&LM options, on an equal basis. <u>1988 ComGas Decision</u>, 17 DOMSC at 138-139; <u>1987 Bay State Decision</u>, 16 DOMSC at 323; <u>1987 Berkshire Decision</u>, 16 DOMSC at 85; <u>1987 Boston Gas Decision</u>, 16 DOMSC at 252; <u>1986 Fall River Decision</u>, 15 DOMSC at 115. To ensure that the Company treated alternative resource options on an equal footing, the Siting Council, in its <u>1986 Fitchburg Decision</u>, 15 DOMSC at 65, ordered the Company to provide the results of its marginal cost study and a discussion of the status of development of C&LM programs.

In this filing, Fitchburg has provided its C&LM Plan, the details of which are discussed in Section III.C.2, <u>supra</u>. In this plan, Fitchburg outlined its objectives for C&LM programs for both its gas and electric operations, and outlined a framework for identifying, implementing and evaluating C&LM programs (Exh. HO-SF-19A). The Company stated in its plan that it will consider future supply and C&LM options within the same planning framework and will use the marginal costs of new supplies as a basis for determining the cost-effectiveness of C&LM programs (<u>id.</u>).

The Siting Council recognizes the Company's intent to treat C&LM options equally with supply options, and encourages Fitchburg to continue with these efforts. The Company, however, has not yet performed a marginal gas cost study, and thus has not provided the results of this study as ordered by the Siting Council. The completion of such a study is a necessary step in the evaluation of the cost-effectiveness of potential supply and C&LM options on an equal footing. While Fitchburg has demonstrated its intention of evaluating supply and C&LM options on an equal footing, it has not demonstrated that it is presently implementing such a planning process.

Accordingly, the Siting Council finds that Fitchburg has failed to establish that its supply planning process treats C&LM options on an equal footing with other resource options.

2. Supply Cost Analysis

In its Decision in the 1986 Gas Generic Order, the Siting Council found that it was appropriate to focus on that portion of its mandate that requires the Siting Council to ensure an energy supply for the Commonwealth "at lowest possible cost." G.L. c. 164, sec. 69H. In so doing, the Siting Council must evaluate whether a company assesses the relative costs of the various resource options it could use to meet its resource needs. This evaluation is critical to least-cost planning since each option may feature unique cost, reliability and other non-price characteristics and since different load additions with varying gas usage patterns impose different types of supply obligations in terms of cost and other non-price characteristics.

In the Siting Council's most recent Fitchburg decision, the Company was ordered to perform an internal study comparing the costs of a reasonable range of practical supply alternatives in the event that the Company's filing indicated the need for a new long-term firm gas supply contract. 1986 Fitchburg Decision, 15 DOMSC at 64-65. This Order was consistent with the Siting Council's Decision in the 1986 Gas Generic Order and was required in order to ensure that the Company's plan minimizes cost.

In the instant case, the Company's obligation to perform such a study was triggered by Fitchburg's decision to add new Boundary and Tennessee NOREX project volumes during the five-year forecast period. Thus, a cost study was required in order to evaluate whether these two new projects were least-cost additions to the Company's existing supply plan, taking adequacy and reliability concerns into account.

The Company did not perform any comprehensive cost studies on Boundary and the NOREX Project (Exhs. HO-SP-7, HO-SP-12; Tr. 130-131).[27] In addition, as mentioned previously, Fitchburg has not completed its marginal cost study to determine the cost-effectiveness of its supply and C&LM options. The Company did provide a "sample calculation" of the total gas costs for Boundary versus supplemental supplies (Exh. HO-RR-5). This calculation however, does not constitute a cost study. For example, the calculation contains a number of undocumented assumptions, including the assumptions that Boundary volumes will displace an equivalent amount of LNG and/or propane, and that the Boundary volumes will have a 75 percent annual load factor. In addition, the calculation does not include a sensitivity analysis, and does not explicitly analyze tradeoffs between price and non-price factors. Further, the calculation does not describe and analyze how the Company determined the Boundary MDQ and AVL. A prudent decision regarding the determination of the MDQ and AVL of new supplies cannot be made without a cost study. Finally, the calculation fails to consider a reasonable range of practical supply alternatives including available C&LM programs. Fitchburg's supply planning process appears to consist of judgments without the benefit of any comprehensive analysis of the costs and benefits of alternative supply options.

Based on the above, Fitchburg clearly has failed to comply with a direct Siting Council order to perform a cost

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27/ The Siting Council notes that the Company also did not provide a cost study regarding the planned expansion of its propane vaporization capacity.

study. This failure to perform cost analyses raises serious questions about the ability of the Company to make informed, cost-justified supply planning decisions. In particular, the Company failed to provide any written documentation describing the decision framework used by Company management to determine what, if any, amounts of the proposed new supplies from the Boundary and NOREX projects, or any other option, would ensure a least-cost, reliable supply plan for the Company's firm customers.

Accordingly, the Siting Council finds that Fitchburg has failed to establish that its planned supply additions were part of a least-cost supply plan.

3. Conclusions on Least-Cost Supply

The Siting Council has found that Fitchburg has failed to establish that: (1) its supply planning process treats C&LM options on an equal footing with other resource options; and (2) its planned supply additions contribute to ensuring a least-cost supply plan. Accordingly, the Siting Council finds that the Company has failed to establish that its supply plan ensures a least-cost supply.

Recently, the Siting Council has clarified the equal footing standard with respect to its review of the supply plans of electric companies within the Commonwealth. see 1989 NEES Decision, 18 DOMSC at 336-338, 348-370; Boston Edison Company, 18 DOMSC 201, 224-226, 250-281 (1989) ("1989 BECo Decision"); Eastern Utilites Associates, 18 DOMSC 73, 100-103, 111-131 (1988) ("1988 EUA Decision"). Now, in determining whether a supply plan minimizes the cost of energy, the Siting Council reviews the company's processes of identifying and evaluating a variety of supply options. In reviewing an electric company's resource identification process, the Siting Council analyzes whether that company identified a reasonable range of resource options by: (1) compiling a comprehensive array of available resource options; and (2) developing and applying appropriate criteria for screening its array of available resource options. In reviewing a company's resource evaluation process, the Siting Council determines whether that company: (1) developed a resource evaluation process which fully evaluates all resource options, including the treatment of all resource options on an equal footing; and (2) applied its resource evaluation process to all of its identified resource options. see 1989 NEES Decision, 18 DOMSC at 336-338, 348-370; 1989 BECo Decision, 18 DOMSC at 224-226, 250-281; 1988 EUA Decision, 18 DOMSC at 100-103, 111-131.

The Siting Council recognizes that fewer resource options may exist for gas companies than for electric companies and consequently that the resource evaluation process may be considerably less complex for gas companies than electric companies. However, the Siting Council concludes that this general framework for reviewing supply plans is applicable to gas companies. Therefore, in future forecast reviews of gas companies, the Siting Council will require gas companies to demonstrate that they have a supply planning process which identifies and evaluates a variety of supply options to ensure a least-cost supply.

The Siting Council's enabling statute also directs it to balance economic considerations with environmental impacts in ensuring that the Commonwealth has a necessary supply of energy. G.L. c. 164, sec. 69H. In the future, the Siting Council directs Fitchburg and other gas companies to include in their supply planning process an adequate consideration of the environmental impacts of resource options.

The Siting Council ORDERS Fitchburg in its next forecast filing to implement a supply planning process which identifies and evaluates a variety of supply options to ensure a least-cost supply, including the consideration of adequacy, environmental impacts, and other non-price factors.

IV. DECISION AND ORDER

The Siting Council hereby REJECTS the sendout forecast and supply plan of Fitchburg Gas and Electric Light Company as presented in its Forecast of Gas Requirements and Resources.

The Siting Council ORDERS Fitchburg in its next forecast filing:

1. to develop a systematic methodology for updating its range of weather data;

2. to provide a detailed analysis demonstrating why its weather database is more appropriate than alternative weather databases for use in forecasting sendout in its service territory;

3. to develop a design year standard based on design conditions for both the heating and non-heating seasons;

4. to: (a) present a systematic analysis of the relationship between sendout, DD, and any other factors it determines to be significant; (b) provide supporting documentation justifying the assumption that heating use per degree day does not increase during extremely cold days, using a statistically valid sample of extremely cold days which provides an adequate representation of potential yearly DD variations; and (c) implement the results of this analysis in its forecasting methodology;

5. to reevaluate its existing methodology, data and assumptions for forecasting sendout in light of the serious concerns that have been raised regarding these factors, and to incorporate the results of this reevaluation in its sendout forecast;

6. to evaluate the expected impact of cogeneration

facilities on its sendout and supply requirements, and to incorporate the results of that assessment in its sendout forecast;

7. to provide: (a) all contracts signed by DOMAC and Bay State for LNG deliveries during the forecast period; and (b) a description and analysis of Fitchburg's capability, particularly under design conditions, to obtain LNG supplies from Bay State in the event of a DOMAC LNG supply disruption;

8. to: (a) provide the results of a marginal cost study or studies that are consistent with the standards of the Massachusetts Department of Public Utilities for determining the cost-effectiveness of C&LM and other resource options; (b) provide an update on the status of its gas C&LM programs; (c) perform a detailed analysis of the cost-effectiveness of various gas C&LM programs relative to available options for new supply, and justify the method of comparison; and (d) describe in detail how the results of its cost-effectiveness analysis of gas C&LM programs are or will be integrated into the Company's supply planning process;

9. to (a) quantify the savings of its existing and planned C&LM programs over the forecast period; and (b) to incorporate these estimates into its base case resource plan and its analyses of adequacy for normal and design conditions;

10. to provide a cold snap analysis which (a) identifies the month or months of the heating season in which a cold snap reasonably can be expected to occur, and (b) demonstrates that Fitchburg has adequate resources to meet cold snap sendout requirements for each month identified; and

11. to implement a supply planning process which identifiesand evaluates a variety of supply options to ensure a least-cost supply, including the consideration of adequacy, environmental impacts, and other non-price factors.

The Siting Council FURTHER ORDERS Fitchburg to file its next forecast on October 1, 1990.

Frank P. Pozniak
Hearing Officer

Dated this 27th day of September, 1989

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of September 27, 1989 by the members and designees present and voting. Voting for approval of the Revised Tentative Decision: David A. Tibbetts (Acting Secretary of Energy Resources); Mary Ann Walsh (Secretary of Consumer Affairs and Business Regulation); Joellen D'Esti (for Alden S. Raine, Secretary of Economic Affairs); Stephen Roop (for John P. DeVillars, Secretary of Environmental Affairs); Dennis LaCroix (Public Gas Member); Madeline Varitimos (Public Environmental Member); Joseph W. Joyce (Public Labor Member); and Kenneth Astill (Public Engineering Member).

David A. Tibbetts

David A. Tibbetts
Chairperson

Dated this 27th day of September, 1989

TABLE 1

Fitchburg Gas and Electric Light Company
Forecast of Firm Sendout by Customer Class

Normal Year
(MMcf)[a]

	1989-90		1992-93	
Customer Class	Heating Season	Non-heating Season	Heating Season	Non-heating Season
Residential Heating	896	419	977	452
Residential Non-heating	68	53	74	59
Commercial	343	176	373	188
Industrial	174	94	192	103
Total Sendout[b]	1,669	796	1,816	859

Design Year
(MMcf)[a]

	1989-90		1992-93	
Customer Class	Heating Season	Non-heating Season	Heating Season	Non-heating Season
Residential Heating	983	419	1064	452
Residential Non-heating	75	53	81	59
Commercial	376	176	406	188
Industrial	192	94	210	103
Total Sendout[b]	1,814	796	1,961	859

Notes:

a. This Table assumes that 1 BBtu equals 1 MMcf.

b. Includes company-use and unaccounted for gas.

Source: Exh. HO-SF-22, Tables G-1 through G-5

TABLE 2

Fitchburg Gas and Electric Light Company
Base Case Design Year Supply Plan
Heating Season
(MMcf)[a]

	1989-90	1990-91	1991-92	1992-93
FIRM REQUIREMENTS:	1825	1874	1923	1972
FIRM RESOURCES:				
Tennessee CD-6	1350	1363	1363	1363
Boundary	76	76	76	76
Penn-York	299	299	299	299
Consolidated	50	50	50	50
Firm LNG	120	120	120	120
Optional LNG[b]	40	40	40	40
Propane from Storage	0	11	0	19
Firm Propane	55	55	55	55
TOTAL RESOURCES:	1990	2014	2003	2022
SURPLUS (DEFICIT):	165	140	80	50
RESERVE:	9.0%	7.5%	4.2%	2.5%

Notes:

a. This Table assumes that 1 BBtu equals 1 MMcf.

b. Optional LNG volumes are set to the maximum annual contract level of 40 MMcf.

Source: Exhs. HO-SP-11, Table G-22D, HO-RR-8

TABLE 3

Fitchburg Gas and Electric Light Company
Base Case Design Year Supply Plan
Non-Heating Season
(MMcf)[a]

	1989-90	1990-91	1991-92	1992-93
FIRM REQUIREMENTS:	1182	1203	1224	1245
FIRM RESOURCES:				
Tennessee CD-6	1542	1563	1584	1605
Boundary	107	107	107	107
Firm LNG	5	5	5	5
TOTAL RESOURCES:	1654	1675	1696	1717
SURPLUS (DEFICIT):	472	472	472	472
RESERVE:	39.9%	39.2%	38.6%	37.9%

Notes:

a. This Table assumes that 1 BBtu equals 1 MMcf.

Source: Exh. HO-SP-11, Table G-22D

TABLE 4

Fitchburg Gas and Electric Light Company
Design Year Contingency Analyses
Heating Season
(MMcf)[a]

1. One Year Delay in NOREX Project

Split-Year	Base Case Surplus (Deficit)[b]	NOREX Contingency	Contingency Surplus (Deficit)[c]	Reserve
1989-90	165	187	(22)	(1.2)%
1990-91	140	0	140	7.5%
1991-92	80	0	80	4.2%
1992-93	50	0	50	2.5%

2. Disruption in Bay State LNG Deliveries

Split-Year	Base Case Surplus (Deficit)[b]	Bay State LNG Contingency	Contingency Surplus (Deficit)[c]	Reserve
1989-90	165	160	5	0.3%
1990-91	140	0	140	7.5%
1991-92	80	0	80	4.2%
1992-93	50	0	50	2.5%

Notes:

a. This Table assumes that 1 BBtu equals 1 MMcf.

b. See Table 2.

c. Contingency surplus (deficit) is derived by subtracting the supply contingency (column 3) from the base case surplus (deficit).

d. An action plan involving the use of some portion of Fitchburg's 30 MMcf of propane vaporization capacity would meet the resource deficiency in split year 1989-90.

Source: Exh. HO-SP-11, Table G-23

TABLE 5

Fitchburg Gas and Electric Light Company
Base Case Design Day Supply Plan
(MMcf)[a]

	1989-90	1990-91	1991-92	1992-93
FIRM REQUIREMENTS:	21.5	22.0	22.5	22.9
FIRM RESOURCES:				
Tennessee CD-6	10.2	10.2	10.2	10.2
Boundary	0.5	0.5	0.5	0.5
Penn-York	2.8	2.8	2.8	2.8
Consolidated	0.5	0.5	0.5	0.5
Firm LNG	7.2	7.2	7.2	7.2
Firm Propane	7.2	7.2	7.2	7.2
TOTAL RESOURCES:	28.4	28.4	28.4	28.4
SURPLUS (DEFICIT):	6.9	6.4	5.9	5.5
RESERVE:	32.1%	29.1%	26.2%	24.0%

Notes:

a. This Table assumes that 1 BBtu equals 1 MMcf.

Source: Exh. HO-SP-11, Table G-23

TABLE 6

Fitchburg Gas and Electric Light Company
Design Day Contingency Analyses
(MMcf)[a]

1. One Year Delay in NOREX Project

Split-Year	Base Case Surplus (Deficit)[b]	NOREX Contingency	Contingency Surplus (Deficit)[c]	Reserve
1989-90	6.9	(2.5)	4.4	20.5%
1990-91	6.4	0	6.4	29.1%
1991-92	5.9	0	5.9	26.2%
1992-93	5.5	0	5.5	24.0%

2. Disruption in Bay State LNG Deliveries

Split-Year	Base Case Surplus (Deficit)[b]	Bay State LNG Contingency	Contingency Surplus (Deficit)[c]	Reserve
1989-90	6.9	(7.2)	(0.3)	(1.3)%
1990-91	6.4	0	6.4	29.1%
1991-92	5.9	0	5.9	26.2%
1992-93	5.5	0	5.5	24.0%

Notes:

a. This Table assumes 1 BBtu equals 1 MMcf.

b. See Table 5.

c. Contingency surplus (deficit) is derived by subtracting the supply contingency (column 3) from the base case surplus (deficit).

d. An action plan involving Fitchburg's planned expansion of its propane vaporization capacity from 7.2 MMcf to 12.0 MMcf daily would meet the resource deficiency in split year 1989-90.

Source: Exh. HO-SP-11, Table G-23

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 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 services 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 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. (See. 5, Chapter 25, G.L. Ter. Ed., as most recently amended by Chapter 485 of the Acts of 1971).

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Bay State Gas Company for Approval of the Second Supplement to the Third Long-Range Forecast of Gas Requirements and Resources	EFSC 88-13

FINAL DECISION

Stephen Klionsky
Hearing Officer
November 30, 1989

On the Decision:

Pamela M. Chan

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TABLE OF CONTENTS

The Siting Council hereby APPROVES the sendout forecast and supply plan filed by Bay State Gas Company for the five years from 1988-89 through 1992-93.

I. INTRODUCTION

A. Background

Bay State Gas Company ("Bay State" or the "Company"), one of the Commonwealth's largest local gas distribution companies ("LDC's"), serves 58 communities in three divisions.[1,2] In the split-year 1987-1988,[3] the Company had an average of 217,572 on-system firm service customers, consisting of 149,116 residential heating customers, 48,603 residential non-heating customers, 19,115 commercial customers, and 738 industrial customers (Exh. BSG-1, Tables G-1 through G-5). Bay State also makes firm sales to off-system customers[4] and sells gas to interruptible customers (id.).

Bay State's forecasts of sendout by customer class in each division for both normal and design years are summarized in Table 1 (Exh. BSG-1, Tables G-1 through G-5).[5] The Company projects an increase of total normalized firm

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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"), Bay State is considered to be a large-sized gas company.

[2] Bay State's three divisions are Brockton (serving 40 municipalities), Lawrence (serving four municipalities), and Springfield (serving 14 municipalities) (Exh. BSG-1, Sec. B).

[3] A split-year runs from November 1 through October 31.

[4] Off-system customers purchase gas for resale outside Bay State's service territory. The off-system customers are both Massachusetts and non-Massachusetts LDC's (Exhs. BSG-1, Table G-24, HO-SP-14).

[5] The heating season is defined as the period from November 1 through March 31. The non-heating season extends from April 1 through October 31.

sendout from 38,919 billion Btu ("BBtu") in 1988-89 to 40,062 BBtu in 1992-93, or an increase of approximately 4.5 percent over the forecast period.

Bay State receives pipeline gas and underground storage return gas[6] from the Tennessee Gas Pipeline Company ("Tennessee") at its Agawam, Northampton, East Longmeadow, Lawrence, Brockton, Mendon, Mahwah and Taunton gate stations for redelivery to Bay State's Brockton, Lawrence and Springfield divisions (Exhs. HO-SP-1).[7] The Company also receives pipeline gas and underground storage return gas from Algonquin Gas Transmission Company ("Algonquin") through take stations located in Brockton, Canton, S. Attleborough, Taunton, and West Medway for redelivery to its Brockton division (id.). Bay State has auxiliary liquefied natural gas ("LNG") facilities in Lawrence and Providence, Rhode Island, and auxiliary propane facilities in Brockton, East Longmeadow, Lawrence, Northampton, Taunton, West Springfield and West Medway (Exh. BSG-1, Table G-14). Additionally, Bay State leases LNG storage and vaporization facilities from Providence Gas Company ("Providence Gas") and Industrial National Leasing Company ("INLC") (id., Table G-24).

In the most recent decision regarding Bay State (Bay State Gas Company, 16 DOMSC 283 (1986) ("1987 Bay State Decision"), the Energy Facilities Siting Council ("Siting Council" or "EFSC") approved the sendout forecast and supply plan of the Company subject to three orders.

6/ Bay State sends gas to underground storage during the non-heating season and the gas is returned for sendout during the heating season.

7/ Bay State's Tennessee volumes are delivered to Granite State Gas Transmission, Inc. ("Granite State"), a wholly-owned subsidiary of Bay State, which, in turn, delivers the volumes to Bay State. Each of the contracts Bay State had previously entered into with Tennessee for pipeline gas and underground storage return have been assigned to Granite State (Bay State Gas Company, 16 DOMSC 283, 287 n.6 (1987)).

B. Procedural History

In September 1988, Bay State requested that the Siting Council approve the Company's sendout forecast and supply plan and the Company's proposal to construct a 19-mile high-pressure natural gas pipeline. This petition was docketed as EFSC 88-13. The high-pressure gas main as proposed in September 1988 would have interconnected with Tennessee's interstate pipeline in Monson, proceeded along public ways through the Towns of Monson, Palmer, Wilbraham, and Ludlow and would have terminated at Massachusetts Municipal Wholesale Electric Company's ("MMWEC") Stony Brook Electric Generating Facility in Ludlow (hereinafter this will be termed the "MMWEC line"). The Siting Council held public hearings on the sendout forecast, supply plan and the proposed MMWEC line on October 26, 1988 in Wilbraham, and on October 27, 1988 in Palmer.

In December 1988, the Company amended the portion of its application relating to the MMWEC line and the proposal was renoticed and additional public hearings were held on March 1, 1989 in Ludlow and on March 2, 1989 in Monson.

Subsequently, on March 23, 1989, the Company submitted an additional application with the Siting Council seeking approval to construct a high-pressure gas pipeline branching off the pipeline proposed in EFSC 88-13 and terminating at the proposed MassPower cogeneration facility in Springfield (hereinafter this will be termed the "MassPower line"). This additional application was docketed as EFSC 89-13.

On June 8, 1989, Bay State submitted a Motion to Consolidate the Facilities Application as Filed and Amended in EFSC 88-13. This motion sought to consolidate in one proceeding the pipeline portion of the application in EFSC 88-13 (the MMWEC line) and the March 23, 1989 pipeline proposal in EFSC 89-13 (the MassPower line). Approval of the Company's motion would mean that EFSC 88-13 would consist only of the Company's request for approval of its sendout forecast and supply plan.

On July 10, 1989, the Hearing Officer granted Bay State's motions to sever its September 1988 forecast and supply plan application (which would continue as EFSC 88-13) from any facility proposal, and to consolidate the facility proposals as EFSC 89-13.[8] All parties that had intervened in EFSC 88-13 were deemed to be parties to both EFSC 88-13 and EFSC 89-13.

Evidentiary hearings on the Company's sendout forecast and supply plan were held on May 19, 22, 24, and 30, 1989. The Company presented four witnesses at the hearings: Charles T. Ellis, senior vice-president, who testified on the Company's supply planning process and conservation and load management programs; Christopher G. Gulick, manager of project development, who testified on the Company's demand modeling, cold snap standard, and planned gas supply; Richard B. Davis, assistant vice-president for rate administration and revenue analysis, who testified on the Company's conservation plans; and David E. Molzan, senior gas supply analyst, who testified on several aspects of the sendout forecast and supply plan. No other parties presented witnesses.

The Hearing Officer entered 171 exhibits into the record, largely composed of Bay State's responses to information and record requests. Six of the Company's exhibits were entered as were 24 of MMWEC's exhibits. On August 7, 1989, the Company and MMWEC submitted initial briefs. The Company filed a reply brief on August 24, 1989 and MMWEC filed a reply letter on September 1, 1989.

8/ On August 18, 1989, the Company moved to amend its facilities application in EFSC 89-13 to "remove that portion of the facility which would be used...to serve MMWEC." The only intervenor to respond to this motion was MMWEC, on August 29, 1989, and it did not object to the facilities amendment. The Hearing Officer hereby grants Bay State's request to amend its facilities application.

II. ANALYSIS OF THE SENDOUT FORECAST

A. Standard of Review

The Siting Council is directed by G.L. c. 164, sec. 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. Fitchburg Gas and Electric Light Company, EFSC 86-11(A), p. 4 (1989) ("1989 Fitchburg Decision"); Berkshire Gas Company, 16 DOMSC 53, 56 (1987) ("1987 Berkshire Decision"); Boston Gas Company, 16 DOMSC 173, 179 (1987) ("1987 Boston Gas 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. 1989 Fitchburg Decision, EFSC 86-11(A), p. 4; Commonwealth Gas Company, 17 DOMSC 71, 77-78 (1988) ("1988 ComGas Decision"); 1987 Berkshire Decision, 16 DOMSC at 55-56; 1987 Boston Gas Decision, 16 DOMSC at 179; Holyoke Gas and Electric Light Department, 15 DOMSC 1, 6 (1986) ("1986 Holyoke Decision"); Westfield Gas and Electric Light Department, 15 DOMSC 67, 72 (1986) ("1986 Westfield Decision").

B. Previous Sendout Forecast Review

In its previous decision, the Siting Council approved Bay State's sendout forecast. The Siting Council, however, ordered Bay State to:

> (1) develop a systematic methodology for the selection of its design year planning standard and to provide in its next forecast filing a detailed and complete explanation and justification for such methodology and resulting standards.
>
> (2) develop a systematic methodology for the selection of its peak day planning standard and to provide in its next forecast filing a detailed and complete explanation and justification for such methodology and resulting standards.[9]

These orders were the result of Siting Council concerns regarding the appropriatenes of the Company's weather data base and its choice of planning standards. In addition, the Siting Council raised concerns regarding the small size of the Company's sendout database which "required the Company to [eliminate] certain explanatory variables from its equations that Bay State might otherwise have wanted to use" (<u>1987 Bay State Decision</u>, 16 DOMSC at 300). The Siting Council also was concerned that the Company's decision to discontinue its use of log-log equations in favor of linear equations and the consequent judgmental adjustments to explanatory variables was made without "systematically examining the structural form of the equation" (<u>id.</u>). The Siting Council considers these issues in its current review.

Bay State's compliance with Orders One and Two and its response to the concerns noted above are discussed in Sections II.C.3.b.i, II.C.4.b.i and II.D.1.a, below.

C. <u>Planning Standards</u>

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 (<u>see</u> G.L. c. 164, secs. 69H, 69I, and 69J).

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[9] The numbers preceding each order are assigned for the purposes of this review only.

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 upon which a company's planning standards are based. The second element of our review is an analysis of the planning standards themselves -- how the company arrived at its normal year, design year and design day standards.[10] A company's standards are used as a basis for projecting its sendout forecast which, in turn, is used for ascertaining the adequacy and cost of a company's supply plan. The Siting Council reviews a company's planning standards to ensure that they are reviewable, appropriate and reliable.

1. Weather Data

The Company presented new weather data which it asserts are appropriate and reliable for use in developing its planning standards (Bay State Brief, p. 8). The Company purchased the new weather data from the Weather Services Corporation ("WSC") of Bedford, Massachusetts, and stated that it uses the data as "a consistent data source for both planning and dispatching purposes and for historical record-keeping" (Exhs. HO-SF-9, HO-SF-10). The new data represent a 21-year data base which will be updated annually (id.). The Company stated that these data are in the form of daily effective degree days ("EDD"), and are specific to each of the Company's three divisions (id.; Exh. BSG-3 (Gulick), p. 10). The Company also stated that it examined the data to determine if it followed a normal distribution before using it to develop planning standards (Exhs. BSG-1, Appendix A, HO-SF-11).

The Company's witness, Mr. Gulick, stated that Bay State chose to use EDD instead of degree days ("DD") for three main reasons: (1) Company studies establish that there is a better correlation between sendout and EDD than between sendout and

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10/ In this decision, "design day" is used synonymously with "peak day."

DD; (2) EDD is more accurate because it is based on data recorded every three to four hours as opposed to the average of daily high and low temperatures used for DD; and (3) EDD is more accurate because DD data is subject to "smoothing" by the National Oceanic and Atmospheric Administration (Tr. 1, pp. 61-63). Mr. Gulick stated that the EDD data for the different divisions are distance-weighted averages of measurements obtained from Class A weather stations in the vicinity of each division (Exh. BSG-3 (Gulick), p. 10).[11] Mr. Gulick stated that the practice of using distance-weighted temperatures is a common WSC technique (Tr. 1, p. 70). Additionally, Mr. Gulick stated that the Company's confidence in the use of weather data from locations outside the Company's service territory is based on the theory that temperatures across a contiguous geographical area are linearly related to each other, and, consequently, the form of the relationship between sendout and temperature across a contiguous geographical area will be equally related (id., pp. 69-70; Exh. BSG-3 (Gulick), pp. 10-11).

In its previous decision, the Siting Council raised concerns regarding the location where the Company's weather data was recorded, the time period used, and the use of DD versus EDD (1987 Bay State Decision, 16 DOMSC at 302). The Company has responded to these concerns by purchasing new weather data which allow it to use consistent, division-specific, current weather data in the form of EDD in the development of its planning standards. Further, the Siting Council finds that the Company has established that the use of distance-weighted data is appropriate as a method for

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[11] The Company indicated that: (1) the weather data for the Brockton division were based on readings taken from airports in Providence, RI and Bedford, MA; (2) the weather data for the Lawrence division were based on readings taken from airports in Bedford, MA and Portsmouth, NH; and (3) the weather data for the Springfield division were based on readings taken from Windsor Locks, CT (Exh. BSG-3 (Gulick), p. 10).

developing division-specific data.

Accordingly, the Siting Council finds that the Company has established that it has an appropriate and reliable weather database for use in the development of its planning standards.

2. Normal Year Standard

To establish a normal year planning standard for each of its divisions, the Company determined the average of the most recent 20 years (1968 - 1987) of EDD data developed for each division by WSC (Exh. BSG-1, Table DD; Tr. 1, p. 52). The normal year standards for the three divisions are 6937 EDD for the Brockton Division, 7290 EDD for the Lawrence Division, and 6831 EDD for the Springfield Division (id.). Mr. Gulick stated that the Company determined that 20 years was the minimum sample size appropriate for determining a normal year standard based on the Company's discussions with a National Weather Service "weather scientist" (Tr. 1, pp. 55-56). Mr. Gulick also stated that the Company felt it was appropriate to limit the sample size to 20 years for the normal year standard so as to ensure that the data was "as up to date as possible in order to remove any kind of long-term trends in temperature data" since the standards are used to look out only five to ten years (Tr. 1, pp. 57-58).

The Siting Council finds that the Company's methodology for determining its normal year standard is reviewable and appropriate. Additionally, because the Siting Council found in Section II.C.1, above, that using the division-specific weather data from WSC is appropriate and reliable, the Siting Council finds that the normal year standards for the Brockton, Lawrence and Springfield divisions are reliable.

While the Siting Council finds that the Company's methodology for determining its normal year standard is appropriate and reliable, and accepts a 20 year sample -- particularly one that utilizes quality weather data -- as a sufficient input in development of an appropriate and reliable normal year standard, it rejects the Company's contention that limiting its sample size to 20 years is preferable to large sample periods. While a larger sampling period may include certain trends which impact upon the reliability of the entire sample, these trends certainly can be discerned and, where warranted, eliminated. The Siting Council notes that, as a rule, larger sample sizes, when accompanied by appropriate statistical analysis, yield more reliable results.

However, here, the Siting Council finds that the Company has established that the normal year standard for each of its three divisions is appropriate and reliable.

3. Design Year Standard

The Siting Council, in the 1986 Gas Generic Order, placed gas companies on notice 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 encountered." 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 recur, 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 found that the largest gas companies in Massachusetts must consider tradeoffs between reliability and cost in establishing design standards. 1988 ComGas Decision, 17 DOMSC at 87; 1987 Boston Gas Decision, 16 DOMSC at 188-190.

In its most recent Bay State decision, while the Siting Council found that the Company had complied minimally with a previous order to provide a rationale for the selection of its design year standards, the Siting Council noted that the Company had not adequately considered the tradeoffs between adequacy and cost. As a result, the Siting Council ordered Bay State to "develop a systematic methodology for the selection of its design year planning standard and to provide in its next forecast filing a detailed and complete explanation and justification for such methodology and resulting standards" (Order One) (1987 Bay State Decision, 16 DOMSC at 303).

a. Description

The Company presented new design year standards of 7649 EDD for the Brockton Division, 7950 EDD for the Lawrence Division, and 7507 EDD for the Springfield Division. These standards were developed by using the most recent 20 years of division-specific EDD data to meet the probability of a occurrence criterion of once in 100 years.

The Company stated that it chose to use the 20 years of data here for the same reason it chose to use 20 years of data in setting the normal year standard. The Company stated that "the use of data from longer time periods would bias estimates of short-term temperature patterns and decrease the reliability of normal and design standards" (Exh. HO-SF-37). The Company indicated that short-term reliability is of primary concern in that the design year standards would be updated each year (Tr. 1, pp. 56-61). Mr. Gulick stated that the Company did not check the 20 years of data for trends because the Company did not believe any trends would be visible over such a short period and because the Company would not want to extrapolate a trend based on only 20 years of data (id., pp. 58-59).

The Company's choice of the one in 100 years criterion was initially made for its design day standard and then applied to the design year standard (Exh. BSG-1, pp. 2-10). The Company stated that it saw "no distinction between the conceptualization of a design day or design year occurrence" (Exh. BSG-1, p. 9). Therefore, it chose to set the same reliability criterion for both standards.

The Company stated that it uses a design year standard "to ensure that Bay State has sufficient supplies and capacity available to meet the demand associated with a colder than normal winter period" (Exh. BSG-1, p. 5). In developing its design year standard, the Company asserted that "there was no substantial cost associated with a design year standard" and, therefore, "there was no trade-off between cost and reliability" (id., p. 9). In support of this position, the Company stated that the costs associated with providing gas during a design winter are both fixed and variable (id., pp. 5, 9). The Company asserted that the fixed costs are "fairly modest" (id., p. 5), identifying these fixed costs as: (1) options on supplemental gas; (2) additional propane and/or LNG storage; (3) inventory carrying costs; and (4) dedicated propane and LNG transportation costs (id.). The Company stated that such fixed costs typically are incurred on a short-term, non-permanent basis, which allows the Company flexibility in evaluating appropriate, low-cost supplemental supply options if colder than normal weather is anticipated or experienced (id., p. 9). The Company identified variable costs as those associated with actual gas production which, the Company asserted, would not be incurred unless colder than normal weather occurred (id.). The Company acknowledged that the new standards would lead to additional costs associated with engineering and plant investment. However, the Company argued that these costs had "minimal impact on Bay State's overall cost of providing service" (Exh. HO-SF-17; Tr. 1, pp. 87-88; Bay State Brief, p. 17).

The Company further argued that since the costs associated with maintaining a design year standard are minimal, a criteria of one in 100 years was proper. The Company acknowledged that if it truly deemed a loss of service to be completely unacceptable then the probability criterion should be chosen to ensure that a design year never occurs. The Company stated that such a standard would have to have a "likelihood of occurrence equal to one year in infinity" (Exh. BSG-1, p. 4). The Company further stated that it was aware that such a policy would likely lead to unreasonable costs being incurred by Bay State, and, therefore, the Company concluded, without additional explanation, that the probability criterion "had to fall within the realm of human comprehension and experience" (id.). Without further explanation in this record, the Company concluded that a criterion of once in 100 years fell within human experience and comprehension and, therefore, was the proper criterion (id.). The Company further noted that the new design year standards for its three divisions, were "very close to Bay State's previous design year standards" (id., p. 10). The Company's witness stated that the Company would continue to evaluate its standard as system and supply changes occur in the future which might result in different levels of system reliability (Tr. 1, p. 93).

In addressing its probability criterion, the Company takes issue with the Siting Council's 1987 Bay State Decision which required the Company to address the balance between cost and reliability. The Company stated that it was concerned by what it perceived as the narrowness of the Siting Council's framework which required a trade-off between cost and reliability. The Company stated that "it appeared that the Council was willing to accept a loss of service if it was cost effective," and that "the framework imposed by the Council is inconsistent with the internal standards of Bay State, the Massachusetts Executive Office of Energy Resources ["MEOER"], and the Massachusetts Department of Public Utilities ["MDPU"]" (Exh. BSG-1, pp. 3-10). The Company presented MDPU and MEOER documents which it claimed support this position (Exhs. HO-SF-7, HO-SF-8).

The Company asserted that it attempted to do its best to address the Siting Council's statutory requirements as reflected in the 1987 Bay State Decision while maintaining the Company's internal standard of no loss of service except in the case of uncontrollable events (Exh. BSG-1, p. 3).

b. Analysis

i. Compliance with Order One

In its last decision, the Siting Council ordered the Company to, "develop a systematic methodology for the selection of its design year planning standard and to provide in its next forecast filing a detailed and complete explanation and justification for such methodology and resulting standards" (1987 Bay State Decision, 16 DOMSC at 303). The Company's compliance with this Order is discussed in the design year standard analysis below.

ii. Design Year Standard

The two bases of the Company's new design year standard are: (1) the use of the 20 years of division-specific EDD data; and (2) the choice of a probability of occurrence criterion of once in 100 years.

First, with regard to the 20-year data sample, the Siting Council adopts here its findings and comments in Section II.C.1.b, above. Division-specific EDD data is appropriate for use in setting a design year standard and the Company's use of this data marks a significant improvement to the robustness of its design year planning. While we accept the 20-year sample here, however, we reject the Company's assertions that no more than 20 years of data should be examined. The Company should be able to determine whether bias exists in longer-term samples. In addition, Mr. Gulick stated that the Company did not check the data for trends because trends would not be detectable based on only 20 years of data (Tr. 1, pp. 56-61). The Company's position is somewhat self-serving, however. The Company ensures that no adjustment to the data will be made by examining only 20 years of data and then claiming that 20 years is too short to discern any trends.

Second, while the Siting Council acknowledges that the Company has made significant strides by developing a systematic methodology for setting design standards, the Company's process for setting a probability of occurrence criterion and the actual criterion itself raise grave concerns that the Company either does not understand the Siting Council's least-cost planning requirements or is unwilling to follow them.

The purpose of the Siting Council's requirement that a gas company set forth a probability of occurrence criterion is not to force the company to plan for a sendout level above which a loss of service is likely to occur. Clearly, in setting design criteria, every company, in some manner, considers the balance between cost and reliability in order to make planning decisions, whether it be some vague, internal, non-quantified position that changes from month to month, or an explicitly set value. We are reasonably certain that no utility has a design year criterion of one in one million or one in one billion. If this were the case, then the utility would be indiscriminately constructing facilities and entering into agreements to prepare for any and all eventualities, actions that would subject its ratepayers to enormous levels of unnecessary costs. The purpose of the Siting Council's requirement that there be an clearly defined probability of occurence is to ensure that the utility is weighing the objectives of cost and reliability reasonably. That is, it is important to ascertain that the utility has planned for the costs necessary to ensure a reliable level of service and that it is not wasting ratepayers' money by spending above that level. An explicit criterion provides a gas company with a firm framework under which to make planning decisions.

For the purposes of this proceeding, the Siting Council finds that the Company has established that the costs of a one in 100 years criterion are acceptable at this point in time. We also find, however, that the manner in which the Company arrived at the criterion is extremely troubling. The Company appears unwilling to accept the importance of considering the balance between cost and reliability set forth above and appears to endorse the development of planning standards which will never actually be reached. While the Company states that it recognizes that such a probability criterion would likely lead to unreasonable costs (Exh. BSG-1, p. 4), it nonetheless continues to maintain that a loss of service is unacceptable. The Company then leaps from this position to a conclusion that the criterion "had to fall within the realm of human comprehension and experience" (id.), and that once in 100 years is within the Company's comprehension, is foreseeable, and is therefore an appropriate criterion. This is simply not an appropriate method for a large gas company (or any sized utility) to use to choose a probability criterion.

Bay State, moreover, clearly asserts that the Siting Council's framework is inappropriate. The Company repeatedly takes issue with the Siting Council's statutory responsibility to ensure least-cost planning and charges that the Siting

Council appears willing to accept a loss of service by a gas company if it is "cost effective." Bay State further states that the MDPU has recognized that the reliability requirements for a gas utility should exceed those for an electric utility and that the MDPU requires "gas companies to minimize cost only to a point where continued service is not endangered." Also, the Company states that the objective of the MEOER is to "preserve continuous service by preventing shortages [and that] [t]his conflicts with a [Siting Council] policy which explicitly or implicitly advocates trading off reliability of service for cost savings" (Exh. HO-SF-8). The Company's comments demonstrate that it fundamentally misunderstands the intent of the Siting Council requirements. As stated above, the purpose of the Siting Council framework is to have utilities set forth an explicit planning criterion instead of operating on an informal, changing or implicit criterion. As such, the Siting Council's framework is consistent with the objectives of the MDPU and the MEOER. The Siting Council has not mandated any particular probability criterion for gas companies, has not found that the reliability standard for a gas company should be less than for an electric company, and certainly has not taken issue with the goal of continuous service. The Company chooses to characterize the Siting Council's position as advocating loss of service and as being at odds with other regulatory agencies when this is not at all the case.

In sum, the Siting Council acknowledges the appreciable improvement the Company has made in the development of a design year standard. For the purposes of this proceeding, we find acceptable the use of 20 years of data and find acceptable the costs of meeting the probability criterion selected by the Company. We also find, however, that the Company's process of selecting its probability criterion and its statements regarding the nature of the Siting Council's framework indicate further improvement is needed in this area.

Accordingly, the Siting Council finds that the Company's design year standards are minimally appropriate and reliable and that the Company has complied with the first order in the 1987 Bay State Decision. In its next filing, the Company is ORDERED to detail the process it has used to establish a design year probability of occurence criterion, the costs associated with that probability criterion over the forecast period, and the cost of other probability criteria considered over the forecast period. Further, if no other probability criteria were considered, the Company should provide justification and include a sensitivity analysis around the selected criterion to show how different criteria levels result in different levels of cost.

4. Design Day Standard

The Siting Council's Decision in the 1986 Gas Generic Order, 14 DOMSC at 97, regarding the development of design criteria applies to both design year and design day standards. 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 its last Bay State decision, in response to its overall concerns regarding the Company's design criteria, and in addition to its order regarding the Company's design year standard, the Siting Council ordered Bay State to "develop a systematic methodology for the selection of its peak day planning standard and to provide in its next forecast filing a detailed and complete explanation and justification for such methodology and resulting standards" (Order Two).

a. Description

The Company stated that after the last Siting Council decision, it undertook a systematic re-evaluation of its design day planning standard (Bay State Brief, p. 14). The Company presented its new design day planning standards as 82 EDD for the Brockton Division, 84 EDD for the Lawrence Division, and 80 EDD for the Springfield Division (Exh. BSG-1, p. 5). These standards were derived by using all 22 years of available division-specific EDD data to meet a probability of occurrence criterion of once in 100 years.

In regard to the Company's decision to utilize all the weather data available to it to develop the design day standards, as opposed to only the most recent 20 years of data for its yearly standards, the Company's witness stated that as "there was no relationship between the coldest days and the trends in temperature and we, in fact, were concerned with identifying the probable occurrence of an extreme day, then it was seen to be more appropriate to keep adding to the sample size to increase the reliability" of the estimate (Tr. 1, p. 58).

The Company stated that its new once in 100 years criterion is more stringent than the Company's previous standard of 77 EDD for all divisions, a level which could be statistically comparable to a reliability level of once in 33 years (Exh. HO-SF-1). The Company asserts that its new design day standards are appropriate because they allow the Company to "achieve its goal of avoiding loss of service under all reasonably foreseeable circumstances" (Bay State Brief, p. 15). The Company initially chose the probability of occurrence criterion for its design day standard and then adopted the criterion for its design year standard. Therefore, the reasons for choosing the design day and design year criterion are identical. In addition, as it did with regard to the design year standard, the Company took issue with the Siting Council least-cost planning requirements.

b. Analysis

i. Compliance with Order Two

In its last decision, the Siting Council ordered the Company to "develop a systematic methodology for the selection of its design day planning standard and to provide in its next forecast filing a detailed and complete explanation and justification for such methodology and resulting standards" (1987 Bay State Decision, 16 DOMSC at 304). The discussion of the Company's compliance with this Order is contained in the design day standard section below.

ii. Design Day Standard

As with the design year standard, the two bases of the Company's design year standard are: (1) the use of division-specific EDD data (in this case, all appropriate division-specific data available to the Company); and (2) the choice of a probability of occurrence criterion of once in 100 years.

In regard to the Company's data sample, the Siting Council finds that the use of the full weather data base available is appropriate. In regard to the Company's probability of occurrence criterion, the Siting Council herein adopts and incorporates the findings set forth in the the analysis of the Company's design year standard (see Section II.C.3 above). As set forth there, the Siting Council acknowledges the significant strides that the Company has made through the development of a systematic methodology for setting standards. However, the process for setting a probability of occurrence criterion and the actual criterion itself raise grave concerns that the Company either does not understand least-cost planning objectives or is unwilling to embrace them.

Accordingly, the Siting Council finds acceptable the use of the data identified by the Company in setting its design day standard. We also find, however, as we did in the preceeding analysis of the design year standard, that the Company's process of choosing its probability criterion and its statements regarding the nature of the Siting Council's requirements indicate further improvement is needed in this area.

Accordingly, the Siting Council finds that the Company's design day standards are minimally appropriate and reliable and that the Company has minimally complied with the second order in the 1987 Bay State Decision. In its next filing, the Company is ORDERED to detail the process it has used to establish a design day probability of occurence criterion, the costs associated with that probability criterion over the forecast period, and the cost of other probability criteria considered over the forecast period. Further, if no other probability criteria were considered, the Company should provide justification and include a sensitivity analysis around the selected criterion to show how different criteria levels result in different levels of cost.

5. Conclusions on Planning Standards

In previous sections of this Order, the Siting Council has found that: (1) the Company has a reviewable, 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's design year standards are reviewable and minimally appropriate and reliable; and (4) the Company's design day standards are reviewable and minimally appropriate and reliable. The Siting Council also has found that the Company minimally complied with Orders One and Two in the 1987 Bay State Decision. In making these findings, the Siting Council noted its concerns with certain elements of the Company's planning standards and ordered the Company to supply certain additional information and perform certain additional analysis in its next filing.

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

D. Forecast Methodologies

1. Normal Year and Design Year

In the 1987 Bay State Decision, the Siting Council approved the Company's annual sendout forecast methodology. However, in that decision, the Siting Council identified concerns related to the size of the data base and certain judgmental adjustments to explanatory variables. The Company asserts that its forecast in this proceeding addresses those concerns in that it is: (1) based on an additional two years of data; (2) based on improved weather data; and (3) improved by the replacement, where possible, of trend variables, such as time, with variables with greater structural validity (Exh. BSG-1, p. 11; Bay State Brief, p. 6). Additionally, the

Company stated that it plans to revise its sendout model due to anticipated new rate classes (Exhs. BSG-1, pp. 1, 65-66, HO-SF-34, HO-SF-55; Tr. 2, pp. 5-10).

a. Description

The Company forecasts annual sendout under normal and design conditions for each firm customer class in each operating division through the use of an econometric model based on weather data and other variables hypothesized to impact gas sendout (Exhs. BSG-1, pp. 10-16, BSG-3 (Gulick), p. 2; Bay State Brief, pp. 5, 9). The Company uses linear equations based on the most recent 18 years of data (1970 - 1987) for the Springfield and Brockton divisions and the most recent 15 years of data (1973 - 1987) for the Lawrence division (Exhs. BSG-1, p. 11, HO-SF-21, HO-SF-41; Bay State Brief, p. 5).[12] The Company's forecasts of normal year and design year sendout requirements are summarized in Table 1.[13]

The Company stated that it chose to discontinue using log-log specifications in its econometric forecasts in favor of simple linear specifications in order to facilitate the use of dummy variables and to avoid potential bias (Exh. BSG-3 (Gulick), p. 3). The Company stated that the use of dummy variables was necessary due to a number of historic events which had a significant short-term impact on gas demand such as pipeline curtailments (id.). The Company also stated that, due to the significant changes in the energy industry during the time frame of the database, a log-log model would be unable to

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12/ The Company stated that detailed sales data for the Lawrence division were not available prior to 1973 (Exh. BSG-1, p. 11).

13/ The Company stated that it forecasts total sendout for the Lawrence and Springfield divisions combined due to the high degree of supply flexibility between the two divisions (Exh. HO-SF-28).

in each of its divisions. For each class and division, the Company develops regression equations to forecast average use per meter and number of meters (Exhs. BSG-1, p. 16, HO-SF-31). The product of these forecasts becomes the sendout forecast for each residential class in each division.

The Company stated that it assumed that general use per meter was directly related to oil price and per capita income, and inversely related to time, gas price and main extension policies (Exh. BSG-1, p. 19). Regression equations developed for each division reflect differing relationships to these variables (id.). Heating use per meter was assumed to be related to effective degree days (normal or design as appropriate), gas price, time, per capita income, and post-1978 non-price related conservation (Exh. BSG-1, p. 23). The Company's witness stated that the Company assumed that use per customer for new customers would be the same as use per customer for existing customers for both general and heating customers on an average basis, with any long term trends due to appliance efficiency being picked up by the regression equations (Tr. 1, pp. 127-128).

The Company forecasts general residential meters to decline in relation to gas price and post-1978 non-price related conservation (Exh. BSG-1, pp. 17-18). The decline in general meters was assumed to be equal to conversions to heating meters, which, in combination with totally new heating customers (incremental heating meters) represented new heating meters (Exh. BSG-1, pp. 16-19). The Company developed regression equations to estimate incremental heating meters based on gas price, per capita income, number of households, and main extension policies (id.).

To estimate residential sendout due to new customers in Monson and Palmer, the Company estimated the number of potential new customers by counting the number of houses in areas where the density was high enough to justify a distribution system, by assuming all new customers would be existing homes converting to gas heat, and by assuming an ultimate 40 percent market share, with penetration at the rate of 2 percent per year (Exhs. HO-SF-27, HO-SF-57, HO-SF-49; Tr. 1, p. 25). The Company's witness, Mr. Gulick, stated that use per meter for the anticipated new customers in Monson and Palmer was assumed to be the same as that for existing customers in Springfield (Tr. 1, pp. 26-28, 168-169).

ii. Commercial

The Company forecasts sendout for both general and heating commercial classes for each division (Exh. BSG-1, p. 23-24).

Depending on the division, commercial heating sales were found to be related to variables including gas price, population employed in the major two digit Standard Industrial Classification ("SIC") codes, effective degree days (in the Brockton division only), main extension policies (in the Brockton division only), oil price (in the Springfield division only), a dummy variable which represented the exaggerated oil price response in the 1979-1981 time frame (in the Springfield division only), and a dummy variable which represented Company-imposed rate of return requirements (in the Lawrence division only) (Exh. BSG-1, pp. 23-28). The Company estimated the number employed in the different SIC codes based on county level information purchased from National Planning Associates ("NPA") (Exh. BSG-1, p. 24, HO-SF-19).

The Company forecasted sendout for the commercial general class for the Brockton and Springfield divisions based on its relationship to the population employed in specific SIC codes, gas price, main extension policies (in the Brockton division), oil price (in the Springfield division), and the dummy variable for exaggerated oil price response (in the Springfield division) (Exh. BSG-1, pp. 25-26, 27-28). For the Lawrence Division, general commercial class sendout was found to be related to gas price, time, and post-1978 non-price conservation (id., p. 31).

To estimate commercial sendout due to new customers in Monson and Palmer, the Company stated that it counted the number of all the non-residential buildings in the potential service territory and estimated the building size (Exh. HO-SF-27). The Company then estimated gas usage per square foot based on information published by the Gas Research Institute (id.). In the case of larger buildings, the Company used actual fuel records, if available. The Company assumed that the larger companies would be on line by the end of 1989, and that the rest would be added at a consistent rate to achieve a 50 percent penetration level after 10 years (id.). The Company stated that buildings which were unoccupied, or that are occupied by dealers of propane, fuel oil, or electric companies were excluded from the estimate (id.). Mr. Gulick stated that several large customers have indicated an interest in purchasing gas from Bay State, and that these potential customers are represented in the estimates (Tr. 1, p. 8).

iii. Industrial

For each division, Bay State forecasts sendout for its industrial heating and industrial general customers separately.

For its Brockton division, the Company stated that industrial heating sendout was found to be related to oil price and the number of employees in a specific SIC category (Exh. BSG-1, p. 26). For its Springfield division, the Company stated that industrial heating sendout was found to be related to gas price, employment in manufacturing SIC categories in Hampden County, and a variable which represented the curtailment of gas volumes on the Tennessee system (id., p. 29). For the Lawrence division, however, the Company asserted that it was not able to develop a theoretically sound, statistically valid regression equation to forecast industrial heating sendout (id., p. 31). The Company stated that sales in Lawrence have remained flat over the last several years after a period of steady growth, with the exception of the addition of a new customer and increased usage by an existing customer (id.). The Company attributed the lack of recent growth in sendout for the industrial heating class in Lawrence to the unavailability of land and rehabilitated buildings in the service territory (id.). Consequently, the Company estimates that sales for this class in Lawrence will remain constant over the forecast period (id., pp. 31-32).

For the industrial general class, the Company developed equations for sendout based on gas price, oil price, employment variables, effective degree days, the dummy variable which represents the exaggerated oil price response in the 1979-1981 time frame, and a dummy variable for post 1978 non-price conservation (Exh. BSG-1, pp. 27, 30, 32). The Company estimated industrial sendout due to new customers in Monson and Palmer in the same manner as commercial customers (Exh. HO-SF-27).

iv. Sales for Resale

The Company stated that it has 13 off-system customers to whom it sells gas for resale (Exh. HO-SF-14). The Company based its forecast of these volumes on firm contract quantities during a normal winter, and firm plus optional volumes during a design winter (Exh. HO-SF-29). The Company is reducing its sales for resale and presented information which shows that its sales for resale obligations will decline over the forecast period by 45 percent in the combined Springfield and Lawrence divisons and by 55 percent in the Brockton division (id.).

v. Company-Use and Unaccounted-For Gas

The Company stated that it determined a fixed percentage for company-use and unaccounted-for gas based on historical data for the Brockton and combined Springfield and Lawrence divisions (Exh. HO-SF-29). The Company stated that the percentages, 3.0228 percent and 5.5632 percent respectively, were applied to both the normal and design year total forecasts (id.).

b. Analysis

Bay State has provided sufficient information to the Siting Council to ensure a complete understanding of the Company's normal year and design year forecasting methodologies. The Siting Council, therefore, finds that Bay

State's normal year and design year forecasting methodologies are reviewable.

In order to determine if the Company's normal year and design year forecasts are appropriate and reliable, the Siting Council must determine if the Company's forecasting methodologies are appropriate for a company of Bay State's size and resources, and are likely to produce reliable results. As noted previously, the Siting Council found the Company's forecasting methodology to be appropriate in the 1987 Bay State Decision. The Siting Council finds here that Bay State's use of an econometric forecasting model disaggregated into service classes and divisions continues to be an appropriate methodology for a large size gas company such as Bay State.

In the 1987 Bay State Decision, however, the Siting Council noted concerns relating to the size of the Company's data base and its use of certain explanatory variables. In this case, the Company has increased its data base with the inclusion of data from the two additional years since the last filing, and has re-evaluated the specific variables appropriate for each customer class in each division. This re-evaluation has resulted in the reduced use of unspecific explanatory variables, such as time, in favor of specific explanatory variables such as per capita income. These revisions have clearly increased the reliability of the Company's forecasting methodologies relative to the last forecast. The Siting Council expects the Company to continue to explore ways to make continued improvements in the reliability of its forecasting methodology as new data sources become available and new explanatory variables are found to be relevant.

In regard to the Company's forecasts for additional sales in the Springfield division as a result of the anticipated system expansion in the towns of Monson and Palmer, the Siting Council notes that the methodologies used for the residential, commercial and industrial classes are basically only "best guesses." However, the Siting Council realizes that until such time as the Company is actually in a position to market gas in these towns, a methodology which accounts for market potential through experience in other areas represents a reasonable means to estimate future sales. Additionally, the Siting Council notes that the firm sales assigned to Monson and Palmer in the forecast are small enough to effectively eliminate concern regarding their impact on the reliability of the overall forecast. Based on the foregoing, the Siting Council finds that Bay State's normal year and design year forecasting methodologies are reliable.

Accordingly, the Siting Council finds that Bay State's normal year and design year forecasts are reviewable, appropriate and reliable.

2. Design Day

a. Description

The Company stated that it developed its design day sendout forecasts for firm customers in its Brockton division and its Springfield and Lawrence divisions combined (Exh. HO-SF-28). The Company calculates sendout by adding the product of design day EDD and daily heating increments to daily baseload values for the divisions (id.). Bay State stated that it calculated the daily baseload and heating increments by regressing the forecasts of total firm monthly sendout against normal monthly EDD (id., Exh. HO-SF-54; Tr. 4, p. 102). The Company indicated that it used a design day of 81.4 EDD for the combined Springfield and Lawrence divisions. This represents the combined 84 EDD for Lawrence (which is approximately 35 percent of the combined total) and 80 EDD for Springfield (which is approximately the remaining 65 percent (id.).

b. Analysis

The Siting Council finds that the Company's design day forecast methodology is reviewable and appropriate. In order to determine the reliability of the Company's forecast, the Siting Council reviews the Company's application of its new design day standards.

The Company has applied its newly developed design day standards to its forecast methodology, thereby effectively addressing the primary concern of the Siting Council in the last case. The Company's method of applying a combined design day standard of 81.4 EDD to determine sendout for the combined Springfield and Lawrence divisions raises some concern, however. While the Siting Council has accepted the Company's practice of combining the Springfield and Lawrence divisions for planning purposes, the Company still should make every effort to forecast sendout for each division as accurately as possible before combining total sendout. The Company develops its annual sendout forecasts for the two divisions customers seperately before combining them, thus recognizing differences in the sendout characteristics between the divisions. Developing a combined design day forecast based on an assumption of identical baseload and heating use factors applied to a combined EDD standard, as the Company's methodology appears to do, eliminates the ability to account for differenes in sendout characteristics between the divisions. We recognize that on a daily basis the impact of such a methodology on the reliability of the total forecast is not likely to be significant enough to effect the adequacy of the Company's supply plan. The Siting Council, however, ORDERS the Company in its next filing to develop a design day forecasting methodology which treats each of its divisions separately, or provide justification that the potential increase in reliability of the forecast does not warrant such an effort.

Accordingly, the Siting Council finds that Bay State's design day forecast is reviewable, appropriate and reliable.

3. Conclusions on Forecast Methodologies

The Siting Council has found above that the Company's normal year and design year forecast methodologies are reviewable, approapriate and reliable. The Siting Council has also found that Bay State's design day forecast is reviewable, appropriate and reliable. Accordingly, the Siting Council finds that the Company's forecast methodologies are reviewable, appropriate and reliable.

E. Interruptible Sales

In its filing, the Company provided a forecast of interruptible sales.[14] According to the Company, forecasts of interruptible sales in a normal year are "based on historical experience and anticipated growth by several large customers attributed to ongoing marketing efforts" (Exh. HO-SF-29). The Company presented detailed documentation of historic interruptible sales in support of its forecast (Exhs. MM-3, MM-14). In a design year, however, the Company stated that during the winter it would be limited to any remaining available contract pipeline and underground storage gas after firm sendout was dispatched (id.; Tr. 4, p. 103). The Company also stated that no spot gas was assumed to be available for interruptible sales during a design heating season (id.). The Company's witness, Mr. Ellis, stated that the Company maintains regular contact with its interruptible customers to maximize interruptible sales when supplies are available (Tr. 3, pp. 112-115). The Company stated that gas prices are flexible enough to compete against these customers' alternate fuels (Exh. HO-SF-52).

14/ General Laws c. 164, section 69I, states that "[e]very gas company shall...file...forecast[s] of gas requirements [that] shall consist of the gas sendout necessary to serve projected firm customers, and the available supplies, for the ensuing five-year period" (emphasis supplied). While interruptible sales do not serve firm customers and a company, under section 69I, is not obligated to file an interruptible forecast, gas companies are required, under c. 164, section 69J, to "include an adequate consideration of conservation and load management. Sales to interruptible customers are an established load management practice for gas companies. Because the Siting Council can thus review interruptible sales as part of its analysis of load management in a company's supply plan (see Sections III.C.2.d and III.F.2.d, below), the Siting Council is assisted if a company provides a projection of interruptible sales which the Siting Council can discuss in its forecast review. In fact, in some circumstances it may be difficult for a gas company to establish that its supply plan includes an adequate consideration of conservation and load management without filing an interruptible sales forecast which supports its conservation and load management goals.

1. MMWEC's Position

MMWEC argues that the Company's sendout forecast, and specifically, the forecast for interruptible sales, is not accurate because it is not based on accurate and complete historical data and reasonable statistical projection methods (MMWEC Brief, pp. 1-2). MMWEC therefore argues that, in keeping with Siting Council regulations and precedent, the Siting Council is obligated to reject Bay State's sendout forecast (id., pp. 2, 4, 5, 9).

In support of its position, MMWEC made several assertions. First, MMWEC stated that Bay State forecasted interruptible sales to MMWEC based solely on "an unfounded assumption" that Bay State would be able to supply gas from the proposed new pipeline for three of MMWEC's turbines rather than for the two that it currently supplies (id., p. 3). MMWEC stated that "merely taking MMWEC's historical use and increasing this by 50 percent based upon an unfounded assumption that Bay State would be able to supply adequate volumes, does not constitute a reasonable statistical projection method and is not consistent with Council precedent" (id., p. 4). Second, MMWEC stated that Bay State's failure to provide an analysis of the impact on NEPOOL's dispatch of MMWEC's Stony Brook plant as a result of increased supplies is a failure to base projections on "valid documented assumptions in accordance with the Council's requirements" (id., pp. 4-5). Third, MMWEC argued that Bay State failed to establish that it would be able to physically provide the level of interruptible gas forecasted for MMWEC due to plans to serve the Masspower cogeneration project in Springfield and the needs of the towns of Monson and Palmer from the proposed pipeline. Fourth, MMWEC argues that Bay State's method for forecasting sales in Monson and Palmer is not based on reasonable statistical projection methods, and therefore, to the extent that the forecasts for Monson and Palmer underestimate sales, the forecasted levels of interruptible sales to MMWEC would be impacted (id., pp. 5-6).[15] Fifth, MMWEC states that because interruptible sales are related to load management, which the Siting Council has jurisdiction to review, under G.L. c. 164, sec. 69J, the Siting Council may review interruptible sales (MMWEC Reply Brief, p. 4). In sum, MMWEC states that "given the fact that Bay State arranges for gas supplies assuming a certain level of interruptible sales requirements, the Council should ensure that Bay State uses realistic and accurate assumptions in forecasting the requirements of its interruptible customers, especially its largest interruptible customer" (MMWEC Brief, p. 9).

2. Bay State's Position

Bay State maintains that: (1) its primary focus is to meet the needs of its firm customers; (2) G.L. c. 164, section 69I, does not require the Company to file a forecast of sales to interruptible customers; and (3) the Company has no obligation to serve interruptible customers (Bay State Reply Brief, pp. 2-3). Bay State admits that it uses interruptible sales to reduce gas costs to its firm customers but maintains that this fact "cannot be turned into a requirement that Bay State develop a supply plan which ensures that Bay State will meet all of the needs of its interruptible customers" (Bay State Reply Brief, p. 4).

Bay State argues further that its forecast accurately projects interruptible sendout for MMWEC and other interruptible customers (id., p. 5). In regard to Bay State's forecast of increased sales to MMWEC, Bay State states that its forecast was based on: (1) an assumption that a new pipeline would be constructed; (2) representations by MMWEC employees to Bay State that if gas were available, the plant would run all three units; and (3) historical gas usage (id., p. 6). In regard to MMWEC's position that an analysis of NEPOOL dispatch

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[15] The Siting Council addresses forecasts of firm sales to Monson and Palmer in Section D.2.b, above.

of the plant was warranted, Bay State asserts that such an analysis was unnecessary as Bay State was already in possession of historical data which reflected a relatively consistent level of sales to MMWEC (id., pp. 7-8). Bay State also challenges MMWEC's position that the forecasts for Monson and Palmer sales were inaccurate. Bay State asserts that MMWEC's argument is unfounded because the Company preformed an in-depth analysis of the potential load in these towns (id., p. 10). The Company maintains that even if Bay State underestimated sales in Monson and Palmer by 100 percent, the result would be a total forecast error of less than one percent (id., p. 8 n.3).

Finally, Bay State contends that "all of MMWEC's arguments are moot because Bay State is no longer proposing to construct the gas main all the way to MMWEC's Stony Brook Facility" (Bay State Reply Brief, p. 1) (see footnote 8, above).

3. Analysis

As noted earlier, the Siting Council recognizes that Chapter 164, section 69I, does not require a gas company to file an interruptible forecast. The Siting Council also recognizes the inherent difficulty in estimating interruptible sales. Ideally, such forecasts should be made with input from the customer where possible. In the absence of such input, or in the case of anticipated new sales, estimates should be based on as much data regarding the customers needs as is available. Here, Bay State has, in fact, provided an interruptible forecast which is based on historic loads for existing customers, and specific data related to the size and nature of anticipated loads. In regard to the planned increase in sales to MMWEC as a result of the proposed pipeline, Bay State presented a forecast of sales which could be reasonably expected. In addition, the revision of Bay State's filing to eliminate any additional service to MMWEC considerably diminishes the relevance of MMWEC's argument on this issue. The Siting Council notes that Bay State is not required to sell gas to its interruptible customers in the event that gas supplies are not available, and, Bay State indicated plans to serve its interruptible market with gas purchashed largely from the spot market, so that the inability to sell gas in the forecasted amounts to a specific customer should not have an unacceptable impact on the costs of the Company's supply plan.[16] Accordingly, the Siting Council accepts the Company's forecast of interruptible sales.

F. Conclusions on the Sendout Forecast

The Siting Council has found that Bay State's planning standards and forecast methodologies are reviewable, appropriate and reliable. Accordingly, the Siting Council APPROVES Bay State's forecast of sendout requirements.

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[16] The Siting Council notes that the accuracy of sendout forecasts for firm customers does not depend upon the availability of adequate gas supplies. The Siting Council may find that a gas company's forecast is reviewable, appropriate and reliable, while addressing questions of adequacy and cost in the analysis of the supply plan.

III. ANALYSIS OF THE SUPPLY PLAN

A. Standard of Review

The Siting Council is charged with ensuring "a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost." G.L. c. 164, sec. 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.[17] 1989 Fitchburg Decision, EFSC 86-11(A), p. 27; 1988 ComGas Decision, 17 DOMSC at 108; 1987 Bay State Decision, 16 DOMSC at 308; 1987 Berkshire Decision, 16 DOMSC at 71; 1987 Boston Gas Decision, 16 DOMSC at 213; Fall River Gas Company, 15 DOMSC 97, 111 (1986) ("1986 Fall River Decision"); 1986 Fitchburg Decision, 15 DOMSC at 54-55; 1986 Holyoke Decision, 15 DOMSC at 27; 1986 Westfield Decision, 15 DOMSC at 72-73; Berkshire Gas Company, 14 DOMSC 107, 128 (1986) ("1986 Berkshire Decision").

In its review of a gas company's supply plan, the Siting Council first reviews a company's overall supply planning process. An appropriate supply planning process is essential to the development of an adequate, least-cost, and low-environmental impact resource plan. Pursuant to this standard, a gas company must establish that its supply planning process enables it: (1) to identify and evaluate a full range of supply options; and (2) to compare all options -- including conservation and load management ("C&LM") -- on an equal footing. 1989 Fitchburg Decision, EFSC 86-11(A), pp. 51-52; 1988 ComGas Decision, 17 DOMSC at 138-139; 1987 Bay State Decision, 16 DOMSC at 323; 1987 Berkshire Decision, 16 DOMSC at 85; 1987 Boston Gas Decision, 16 DOMSC at 252; 1986 Fall

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[17] 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.C.3, below.

River Decision, 15 DOMSC at 115.[18]

The Siting Council next reviews a gas company's five-year supply plan to determine whether that plan is adequate to meet projected normal year, design year, peak day, and cold-snap firm sendout requirements.[19] In order to establish adequacy, a gas company must demonstrate that it has an identified set of resources which meet its projected sendout 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. 1988 ComGas Decision, 17 DOMSC at 108; 1987 Bay State Decision, 16 DOMSC at 308; 1987 Berkshire Decision, 16 DOMSC at 71; 1987 Boston Gas Decision, 16 DOMSC at 312.

Finally, the Siting Council reviews whether a gas company's five-year supply plan minimizes cost. A least-cost supply plan is one that minimizes costs subject to trade-offs with adequacy and environmental impact. 1988 ComGas Decision, 17 DOMSC at 109; 1987 Bay State Decision, 16 DOMSC at 309;

18/ In 1986, G.L. c. 164, sec. 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 ComGas Decision, 17 DOMSC at 71, 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 meet projected sendout requirements (pp. 123-126).

19/ 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: 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.

1987 Berkshire Decision, 16 DOMSC at 72; 1987 Boston Gas Decision, 16 DOMSC at 214; see 1989 NEES Decision, 18 DOMSC at 337. 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. Previous Supply Plan Review

In the 1987 Bay State Decision, the Siting Council approved Bay State's supply plan. However, the Siting Council ordered Bay State to: (3) Submit a cold-snap analysis in its next filing.[20]

In addition, in its last Order, the Siting Council noted weaknesses in the Company's supply planning processes stating that "in the absence of formal documentation of its supply planning process and decisions, the Company potentially deprives itself of an organized method of analyzing options, making decisions, reevaluating past decisions in light of changing circumstances, and providing the necessary justifications for such decisions" (id., p. 322). Further, the Siting Council noted that "this sort of supply planning process is not appropriate for a company of Bay State's size and resources. In order to ensure that the Company continues to make decisions which result in least-cost supply, Bay State should develop and implement methodological changes designed to address the demands of a more competitive gas supply environment" (id., p. 325).

Bay State's compliance with Order Three and its response to the concerns noted above are discussed in Section III.C, III.E.3.b.i and III.F, below.

20/ For purposes of this review this Order is referred to as Order Three of the 1987 Decision.

C. 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. 1989 Fitchburg Decision, 86-11(A), pp. 54-55; 1989 NEES Decision, 18 DOMSC at 336-338, 348-370; Boston Edison Company, 18 DOMSC 201, 224-226, 250-281 (1989) ("1989 Boston Edison Decision"); Eastern Utilities Associates, 18 DOMSC 73, 100-103, 111-131 (1988) ("1988 EUA Decision"); 1987 Boston Gas Decision, 16 DOMSC at 71-72. 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. 1987 Bay State Decision, 16 DOMSC at 332. For the Siting Council to determine that the supply planning process is appropriate, the process must be fully documented. 1987 Boston Gas Decision, 16 DOMSC at 247, 249; 1987 Bay State Decision, 16 DOMSC at 332; 1987 Berkshire Gas Decision, 16 DOMSC at 84.

Our review of a gas company's supply planning process has focussed primarily on whether (1) the process allows companies to adequately consider conservation and load management options, and (2) the process treats all resource options -- including C&LM options -- on an equal footing. 1989 Fitchburg Decision, EFSC 86-11(A), pp. 51-52; 1988 ComGas Decision, 17 DOMSC at 138-139; 1987 Bay State Decision, 16 DOMSC at 323; 1987 Berkshire Decision, 16 DOMSC at 85; 1987 Boston Gas Decision, 16 DOMSC at 252; 1986 Fall River Decision, 15 DOMSC at 115.

In the 1989 Fitchburg decision, the Siting Council clarified its standard of review, noting that our review of a gas company's supply planning process, like our review of an electric company's process, must include an analysis of the company's documented process for identifying and evaluating resource options. 1989 Fitchburg Decision, 86-11(A), pp. 54-55. Only through a comprehensive analysis of a company's process for identifying and evaluating resource options can the Siting Council determine specifically whether the process allows for adequate consideration of C&LM and treats all options on an equal footing, and moreover, whether the process as a whole enables the company to achieve an adequate, least-cost, and low environmental impact supply plan.

Now, in reviewing a gas company's process for identifying and evaluating resources, the Siting Council determines whether the company: (1) has a process for compiling a comprehensive array of resource options -- including pipeline, supplemental supply, conservation, load management, and other resources; (2) has established appropriate criteria for screening and comparing resources within a particular supply category; and (3) has a mechanism in place for comparing all resources on an equal footing, i.e., across resource categories.[21]

The Siting Council recognizes that fewer resource options may exist for gas companies than for electric companies and consequently that the resource identification and evaluation process may be considerably less complex for gas companies than electric companies. However, the Siting Council concludes that the general framework for reviewing the supply planning process specified above is applicable to gas companies. We also recognize that each gas company will have different supply planning options and needs and that each supply planning process will be different.

While the Siting Council acknowledges that the organization of our review in this case differs somewhat from that of other gas company cases, this reorganization does not establish new regulatory standards or place additional burdens on gas companies. Rather, our intent is to better track the manner in which, we believe, gas company resource decisions are actually made, and to underscore our emphasis on the importance of the planning process as the most critical factor in the implementation of a least-cost plan.

21/ The Siting Council's review of whether the application of the Company's planning process has resulted in a least-cost plan is addressed in Section III.F, below.

2. Identification and Evaluation of Resource Options

The Company's witness, Mr. Ellis, testified that the Company is continually searching for new gas supplies to satisfy growing demand and to identify possible lower cost supplies to replace existing supplies (Tr. 3, pp. 10-11). The Company identified three generic types of resources available to gas companies -- pipeline (baseload) natural gas supplies, supplemental (peaking) gas supplies, and conservation (id., pp. 81, 84). In regard to load management, the Company stated that "load management is independent of any one gas supply and is concerned more with the effective utilization of gas supplies" and, as such, has applications across all supplies (id., p. 85). The Company's process for identifying and evaluating potential supply options within each supply type and across supply types is described below.[22]

a. Pipeline Gas Supplies

Mr. Ellis stated that gas companies in the northeast only have two sources of pipeline gas -- the Gulf Coast in the United States and the province of Alberta in Canada -- and added that the addition of baseload supplies from these sources largely is tied to the ability to arrange transportation (Tr. 2, pp. 44-45). The Company did not describe how it identifies specific producers in these two areas who have gas available for purchase.

Mr. Gulick stated that the Company contracts for baseload pipeline gas primarily to serve the needs of its firm customers (id., p. 56). Mr. Gulick also stated that the Company attempts to purchase blocks of baseload gas which the

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22/ The Siting Council reviews only the Company's general supply planning process here to determine if the Company's process allows it to make appropriate decisions to achieve an adequate and least-cost supply. In its review of the adequacy and cost of the Company's actual five year supply plan, the Siting Council reviews the Company's application of its supply planning process in making specific decisions. See Sections III.E and III.F, below.

Company anticipates it will eventually need to serve firm load, and then attempts to maximize its ability to move the gas to where it can be utilized most effectively for interruptible loads (Tr. 2, pp. 59-60).

The Company asserted that in deciding between pipeline suppliers, Bay State's primary goal is to add to the diversity of the Company's supply plan (Tr. 3, pp. 83-86). According to Mr. Ellis, the Company "might pay a premium" in order to ensure a diversified mix of pipeline supply (id., p. 86). The Company stated that other factors which impact its choice of pipeline gas supply include the supplier's reserve level, the ability of the supplier to build and/or secure pipeline facilities to deliver the gas, and the time frame required to receive the supplies (Exh. HO-SP-44). Mr. Ellis stated that the time frame required to develop a new source of baseload pipeline supply has increased from one to two years in the mid-1960's to five to eight years today (Tr. 3, pp. 12-14). The Company stated that the factors which effect the cost of pipeline gas are pipeline demand charges, pipeline commodity costs, the index to which the commodity costs are tied, take-or-pay provisions, and minimum purchase levels (Tr. 2, pp. 59-60).

The Company stated that it purchases spot pipeline gas whenever the price is less than contract gas, or it is needed in addition to contract quantities (Exhs. HO-SP-4, BSG-3 (Molzan), p. 8). The Company stated that "[b]ids are received each month from numerous spot gas markets and the cheapest bids are accepted first, and so on, up until the anticipated daily demand for the month is reached" (Exh. HO-SP-22).

The Siting Council notes that the pipeline supply options available to gas companies are limited by transportation availability. The Company's process for identifying pipeline supply options is appropriate considering this limitation. Further, the criteria which the Company asserts it applies in evaluating pipeline supply options are reasonable. Criteria which include diversity, reliability, cost and timing clearly allow Bay State to pursue the best overall options in making supply decisions. Accordingly, the

Siting Council finds that the Company's process for identifying and evaluating pipeline resource options is appropriate for making decisions among pipeline options.

b. Supplemental Gas Supplies

Mr. Ellis stated that the supplemental supplies available to the Company include LNG, propane, and non-traditional options, such as the "oil/gas swap" arrangement with the Northeast Energy Associates cogeneration facility in Bellingham ("NEA") (Tr. 3, pp. 11-12, 17). See Section III.C.2.b, below, for a description of this arrangement; see also, Northeast Energy Associates, 16 DOMSC 335, 368 (1987).

The Company stated that near-term decisions regarding supplemental supplies are made on an annual basis at the beginning of the winter heating period. At that time, the Company: (1) determines the amount of propane to be contracted; (2) makes preliminary plans regarding the amount of LNG to be purchased on the spot market (which is dependent on how much of its own gas it will liquefy); and (3) makes arrangements for vaporization services, if necessary, with Providence Gas Company ("Providence") (Exh. HO-SP-44; Tr. 2, p. 64, Tr. 4, pp. 90-94).

The Company stated that the primary factor in purchasing propane is the need to find a supplier that can deliver relatively large amounts directly to the LP-air plants (Exh. HO-SP-44). This is the case because Bay State can vaporize a relatively large amount of propane daily at its LP-air plants, but its storage capacity for this gas is relatively small (id.). Therefore, the Company typically purchases propane from the Newington, New Hampshire import terminal or the Providence, Rhode Island import terminal (id.). The Company also stated that it does not typically contract in advance for a large amount of propane because large quantities are available at both terminals (Tr. 2, p. 93). The Company did not identify propane suppliers with import rights at the terminals specified. Further, the Company did not indicate whether it has a process in place for identifying other potential suppliers of propane.

In regard to LNG, the Company identified DOMAC as its only outside supplier. The Company stated that decisions regarding LNG -- that is, whether the Company liquefies its own gas or purchases spot supplies from DOMAC -- are made based on the availability of gas to liquefy, the costs of liquefying gas, the costs of purchasing LNG from DOMAC, and the costs of transporting either source to storage (Exh. HO-SP-44; Tr. 2, pp. 100-101).

The Company stated that the primary criterion used in choosing between these near-term options is cost (Tr. 2, p. 100, Tr. 4, pp. 90-94). The Company also stated, however, that system operating constraints may override the cost factor at certain times during the winter period (id.; Exh. HO-SP-44).

In regard to long-term supplemental supplies, the Company stated that capital and variable costs are considered in making decisions as to whether the increments come about through long term contracts, expansion of existing facilities, or development of new facilities (Exh. HO-SP-44). According to the Company, these costs include the capital cost of new supplemental supply facilities, the commodity cost of supplemental feedstocks, the cost of converting the feedstocks into the end product, and the commodity cost of supplementals if purchased in final form (id.). The Company stated that it also considered the availability of feedstocks to produce supplementals, and the index to which the feedstocks of supplemental gas supplies are tied (id.).

Mr. Ellis stated that the Company pursues diversity in its supplemental supplies through the use of several LNG liquefaction and LP-air facilities, purchases from numerous propane suppliers, LNG purchases from DOMAC, and unique arrangements such as the oil/gas swap with NEA (Tr. 3, pp. 86-87). Mr. Ellis further stated that the Company's options for new supplemental supplies are affected by the difficulty in siting new LNG and LP-air facilities (Tr. 3, pp. 15-16). Mr. Ellis indicated that siting and construction of new supplemental facilities would take three to five years (id.).

The Siting Council notes that the range of supplemental supply types available to gas companies -- both near-term and long-term -- is limited. The Company's supply planning process, however, overcomes this limitation to some degree as evidenced by the identification of unique opportunities such as the NEA oil/gas swap. Therefore, the Siting Council finds that Bay State's process for identifying both near-term and long-term supplemental supply options is appropriate.

At the same time, the Company has established reasonable criteria for the evaluation of supplemental options. In addition to cost, criteria such as availability, proximity of supply, and operations flexibility make sense for decisions regarding near-term propane and LNG. Similarly, a process that evaluates long-term options based on cost, diversity and timing is reasonable.

Accordingly, the Siting Council finds that the Bay State's process for identifying and evaluating supplemental resource options is appropriate for making decisions among supplemental gas options.

c. Conservation

The Company defined conservation as "any cost-effective action which permanently reduces load" (Exh. BSG-3 (Ellis), p. 3). The Company indicated that its conservation efforts still are largely in the developmental stage, but stated that the Company is taking steps to identify, evaluate and implement cost-effective conservation measures (id.).

The Company stated that its on-going efforts to identify conservation programs and develop appropriate evaluation criteria include: (1) participation in a joint program with the Massachusetts Natural Gas Council's ("MNGC") conservation committee to develop a list of conservation programs; and (2) completion of an in-house survey of literature on conservation measures (Exhs. BSG-1, pp. 77-78, BSG-3 (Ellis), p. 3, BSG-3 (Davis), pp. 2, 7; Tr. 4, p. 8).

The Company stated that the MNGC had contracted with Energy Investment Inc. to conduct a nationwide search for both conservation and load management programs for all customer classes, and to develop a database of the programs (Tr. 4, pp. 8, 37; Exh. HO-RR-12). The Company provided an interim status report as well as the final report from Energy Investment, Inc. and indicated that it would be incorporating the results of the final report in the development of future programs (Exhs. HO-RR-13A, HO-RR-13B).

The Company stated that its in-house survey of current conservation literature was intended to be a compilation and summary of existing information on utility sponsored conservation programs (Exh. HO-SP-31). The Company indicated that the survey primarily related to mandated conservation programs, and addressed issues such as the characteristics of program participants, the effectiveness of various programs and the costs of programs to non-participants (Exh. HO-SP-31A). The Company stated that the results of the survey will be taken into consideration in the evaluation of conservation programs in the future (Exh. HO-SP-31). The Company stated that it also was installing remote meter reading devices on residential customer meters to allow Bay State, among other things, to evaluate the effectiveness of future conservation measures (Exh. BSG-1, p. 80).

Mr. Davis testified that the long-range goal of the company is to "implement cost-effective conservation programs" (Tr. 4, p. 57). The Company stated that for a conservation program to be considered cost effective, and therefore to be implemented, "the present value of the avoided gas cost has to be greater than the cost of the program" (Exh. HO-SP-34). The Company further stated that it has developed an avoided cost study for review at the MDPU, and that the MDPU's determination regarding the study will be the basis of the determination of cost-effectiveness for programs under consideration in the future.

In addition, the Company asserted that it had previously identified and rejected several conservation programs because a marginal cost study had indicated they were not cost-effective (Exh. BSG-1, p. 79). The Company stated that it was currently re-evaluating these programs to determine their cost-effectiveness relative to the avoided cost study (id., Exh. HO-SP-32). The Company did not identify specifically which conservation programs were being re-evaluated (Exhs. BSG-1, pp. 79-81, BSG-3 (Davis), pp. 6-8, HO-SP-32, HO-SP-33; Tr. 4, pp. 45-57).

The Siting Council notes that the implementation of cost-effective conservation programs is still largely in the developmental stage throughout the gas industry. As such, the Company's participation in the MNGC effort to identify programs for evaluation is appropriate. The Siting Council also notes, however, that large companies reasonably may be expected to fully integrate conservation in their planning process. The Siting Council encourages the Company, therefore, to increase its own efforts to identify conservation programs through solicitation of input from other third parties, and through further literature searchs. The Company's in-house survey of conservation programs represents an useful "first step" in the identification of conservation options. However, in restricting the scope of its survey primarily to mandated conservation programs such as its own RCS program, the Company substantially limited the usefulness of the report results. Nonetheless, the Siting Council finds that Bay State's process for identifying conservation options is appropriate at this time.

However, the Company's process for evaluating conservation options remains essentially undeveloped. While evaluating conservation programs based on MDPU-approved avoided cost calculations ensures an appropriate cost comparison, such a process will allow the Company to evaluate conservation options on one basis only. Clearly, other criteria such as timing (i.e., program on-line dates), are critical in comparing conservation options. While program cost certainly is a major factor, any process which makes a "first cut" based on cost potentially deprives the Company of certain options which provide significant timing advantages and therefore may warrant somewhat higher costs. Therefore, the Siting Council makes no finding in this proceeding regarding the Company's evaluation criteria for conservation measures and notes that Bay State will be expected to more fully develop its planning process for conservation measures by incorporating non-price factors, including timing, into its evaluation process.

d. Load Management

As noted previously, the Company stated that it views load management as distinct from conservation. The Company indicated that it makes this distinction because conservation programs are designed to permanently reduce load, while load management programs may take one of several forms: (1) strategic load growth; (2) load shifting; and (3) strategic, short-term load elimination (Exhs. BSG-1, p. 81, BSG-3 (Ellis), p. 3).

In regard to the strategic addition of load, the Company stated that load management programs in this category serve primarily to improve the Company's effective utilization of current and anticipated gas supplies through an improved load factor (Exh. BSG-1, p. 83). As such, they allow the Company to realize both cost and reliability benefits for their firm customers (id., Exh. BSG-3 (Ellis), pp. 4-5; Bay State Brief, p. 41). In order to ensure that the potential from strategic load additions is fully realized, Company personnel have been "assigned to continually monitor the sales activity of all of Bay State's interruptible customers as well as the cost of their alternate fuel" (Exh. HO-SF-52). In addition, the Company stated that it has executed new interruptible contracts with all of its interruptible customers, contracts which contain flexible pricing provisions which ensure that Bay State has adequate flexibility to compete against the customers' alternate fuel" (id.). The Company stated that "whenever a reduction in sales is noted, the customer is immediately contacted to determine the cause of the reduced gas usage and if the reduction in gas usage is due to a reduction in the cost of the customer's alternate fuel, the price for the interruptible gas to the customer is immediately adjusted to entice the customer to return to gas service" (id.). The

Company asserted that it also has identified gas air-conditioning and natural gas vehicle programs as possible strategic load addition programs (Exh. HO-SP-42).

The Company did not identify any load shifting programs. The Company defined load shifting as the movement of gas demand from one time period to another and stated that at present there are no feasible means of shifting peak load to off-peak periods (Exh. BSG-1, p. 83). The Company identified approximately 73 percent of its peak load as temperature sensitive, and therefore not available for load shifting of any kind (Exh. BSG-3 (Ellis), p. 8). The Company also stated that some peak loads which are not temperature sensitive, such as the use of hot water, could be shifted within the gas day (id.). However, the Company indicated that such shifting would not provide any benefits to Bay State since it purchases supplies on a daily basis rather than an hourly basis and the distribution system is designed to absorb hourly swings in sendout requirements during the day (id.).

In regard to strategic load elimination programs, the Company identified any firm customer with dual fuel capability as a potential target for strategic load elimination on selected days during the winter (Exh. BSG-1, p. 81). The Company stated that the potential benefits of such programs would be the reduction of the cost of gas to firm customers, and the ability to delay new supplemental gas capacity (Exh. BSG-3 (Ellis), p. 9). The Company stated that for a load elimination program to be cost-effective, it would have to cover all the direct and indirect costs of the program (id., pp. 9-20).

The Company has identified the three general load management types which are available to it, and has a process in place which allows it to identify the potential customers within each general type. In addition, the MNGC effort includes identification of load management programs as well as conservation programs. Therefore, the Siting Council finds that Bay State's process for identifying and evaluating load management options is appropriate for making decisions among load mangement options.

e. Consideration of All Resources on an Equal Footing

The Company stated that, in pursuing new supplies, the primary goal of its supply planning process is to maintain sufficient flexibility and diversity in its gas supply plan to allow for the dispatch of the lowest cost gas (Exhs. BSG-1, p. 84, HO-SP-47; Tr. 2, pp. 57-58). The Company asserted that in order to accomplish this goal, it purchases gas by whatever means practical at a cost which is less than or equal to the Company's long-run avoided cost (id.). The Company indicated that this practice applies to all components of its gas supply portfolio but also stated that there are limits to the use of some types of supplies, such as supplementals and conservation (id., pp. 84-85). The Company further stated that a consistent methodology for making supply decisions can be developed for each supply type but not necessarily across supply types (id., p. 81). Finally, the Company stated that its supply planning process is informal, and there is no documentation of the process, but asserted that the results, low rates to ratepayers, speak to its effectiveness (Exh. HO-SP-44).

The Company indicated that its supply planning process allows it to make both short-term and long-term supply decisions, and that during the course of a year, it makes short-term decisions regarding purchases of spot pipeline supplies, wintertime use of supplementals, and implementation of load management programs. The Company stated that it considered load elimination programs as alternatives to peaking supplies but not to baseload supplies, and stated that a cost analysis of these programs would be performed for each upcoming winter (Tr. 3, pp. 52, 68). The Company asserted, however, that the reliability of load elimination as a resource option would be less than that of traditional supplies. The Company also stated that it does not consider conservation programs to be replacements for short-term supplemental supply options (Tr. 3, p. 70).

In regard to long-term supply planning, Mr. Gulick stated that the Company is "continually looking out ahead as to what potential requirements will be in our firm markets over a forecast horizon and identifying the kinds of gas supplies that we will need" (Tr. 2, p. 57). The Company indicated that in evaluating which supply options to pursue, the Company considers non-price factors such as reliability, flexibility, potential volume, and time required to develop the supply (id., p. 81; Exh. HO-SP-44).

The Company asserted that baseload pipeline gas supplies are the most reliable and typically the least costly option available to the Company (Tr. 2, p. 38; Exh. HO-SP-44). The Company also noted, however, that opportunities to add baseload pipeline supplies are rare (id., pp. 57-61). Consequently, the Company stated that it purchases large blocks of new baseload supplies when they do become available (id.). The Company stated that "the amount of pipeline gas which is placed under firm contract is determined by attempting to balance the incremental cost of buying the next unit of firm daily supply against the cost of providing that unit of supply from supplemental sources" (Exh. HO-SP-44).

According to the Company, it views conservation as a long-term option for baseload supply which generates savings that increase as programs are implemented (Bay State Brief, p. 40). The Company also stated that as programs are identified they will be evaluated against other supply options on the basis of avoided cost (id., p. 39). The Company indicated, however, that it does not incorporate conservation programs as a resource in its supply plan directly, but asserts that energy savings from conservation programs reduce the actual demand which is the basis from which future demand is forecasted (Tr. 3, pp. 68-70). The Company therefore argues that its supply plan reflects conservation because supply requirements are adjusted once the impact of programs are reflected in the forecast (id.).

Mr. Ellis stated that in the future the Company will be utilizing an up-to-date long-run avoided cost, as determined by the MDPU, in making all long-term decisions, and will compare conservation, supplemental, and load management options, against new baseload supplies (id., pp. 80-83).

The Siting Council consistently has held that in order for a gas company's supply planning process to minimize cost, that process must adequately considers alternative resource additions, including C&LM options, on an equal basis. <u>1989 Fitchburg Decision</u>, EFSC 86-11A, p. 51; <u>1988 ComGas Decision</u>, 17 DOMSC at 138-139; <u>1987 Bay State Decision</u>, 16 DOMSC at 323; <u>1987 Berkshire Decision</u>, 16 DOMSC at 85; <u>1987 Boston Gas Decision</u>, 16 DOMSC at 252; <u>1986 Fall River Decision</u>, 15 DOMSC at 115. While the Company asserts that its supply planning process is continuous, and stated that its future plans call for C&LM options to be evaluated on the same basis and at the same time as other options, the Siting Council notes that the Company's process basically continues to treat supply options separately. The Company's statement that a consistent methodology can be developed within a supply category, but not across categories, demonstrates the Company's continued failure to appreciate the fundamental tenets of least-cost planning. A gas company's supply planning process should be sufficiently robust to accommodate the unique characteristics of supply options while ensuring that the full range of supply options are identified and evaluated at a specific point in time. By categorically placing limits on the ability of certain resources to meet specific needs (such as the ability of conservation measures to replace supplemental supplies), the Company runs the risk of missing an opportunity to add a least-cost supply resource to its mix. Clearly, a full complement of supply resources is needed to meet the Company's sendout requirements over a given period, and a process which automatically separates out specific supplies for specific load configurations is not warranted. As long as the Company continues to utilize a framework which deals with supply decisions on a case by case basis rather than through a comprehensive process, we have no confidence that the Company's planning process consistently will ensure a least-cost mix.

Accordingly, the Siting Council makes no finding as to whether the Company's supply planning process ensures the treatment of all supply options on an equal footing.

3. Conclusions on the Supply Planning Process

In the 1987 Bay State Decision, the Siting Council found that the Company operated pursuant to a minimally acceptable supply planning process (16 DOMSC at 324). While the Siting Council also found in that decision that the Company's specific decisions regarding supply additions allowed it to meet sendout requirements in a least-cost manner, the Siting Council expressed concern regarding the informal and undocumented nature of the processes which the Company followed in deciding on new sources of supply (Id., p. 325).

In this proceeding, the Siting Council has found that Bay State's proceses for identifying and evaluating pipeline resource options, supplemental resource options, and load management options are appropriate. In addition, the Siting Council has found that Bay State has an appropriate process for identifying conservation options. However, the Siting Council has been unable to find that the Company has an appropriate process for evaluating conservation programs or ensuring the treatment of all supply options on an equal footing. Despite these significant problems, the Siting Council finds that the Company's supply planning process has improved since the Siting Council's previous Bay State review, and that, on balance, the Company's supply planning process allows for an adequate identification and evaluation of supply options. Accordingly, the Siting Council finds that the Company has established that its supply planning process enables it to make least-cost supply decisions.

In making this finding, the Siting Council notes that Bay State's adoption of a systematic and documented process for comparing resources across supply categories is long overdue. The Company readily admits that its supply planning process remains informal and undocumented. In our opinion, the increased number of options available to gas and electric companies, and, consequently, the increased complexity of the decisions which must be made, require thorough, well-documented evaluations of the bases for such decisions. The Siting Council simply cannot accept the Company's continued assertions that the Company's low rates alone are sufficient justification of the sophistication of the Company's supply planning process. First, while a company's rates may be relatively low, it does not follow automatically that its gas supply is the least-cost supply for its customers. More importantly, without any discernable planning guidelines, there is no assurance that future gas supply will be least-cost or even low cost. Finally, the Company's own statements regarding the need for inclusion of non-price factors in its supply planning process belie the Company's assertion that a low cost of gas to firm ratepayers relative to other companies should, in the end, be the only documentation necessary to establish the acceptability of a supply planning process.

The Siting Council recognizes the Company's interest in maintaining flexibility in its planning process so that it can pursue creative supply options. The Siting Council also recognizes the impressive level of experience that Bay State management brings to that task. These factors, however, are no substitute for a systematic and well documented methodology for identifying and evaluating supply options. The Siting Council notes that the Company is taking one significant step towards a consistent, systematic supply planning process through its avoided cost study and response to MDPU and Siting Council directives.

The Siting Council therefore ORDERS the Company to include in its next forecast filing: (1) a detailed listing of the all supply options identified by the Company for consideration for the forecast period (whether pursued or not); (2) a detailed description of the criteria the Company either used or will use in evaluating the options; and (3) a thorough explanation of how the Company will ensure that all resource options are considered on an equal footing.

The Siting Council's enabling statute also directs it to balance economic considerations with environmental impacts in ensuring that the Commonwealth has a necessary supply of energy. G.L. c. 164, sec. 69H. In the future, the Siting Council directs Bay State to include in their supply planning process an adequate consideration of the environmental impacts of resource options.

D. 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 potentially impact the cost of the supply plan. The Siting Council then reviews the adequacy of the Company's supply plan Section III.E, below, and the cost of the Company's supply plan in Section III.F, below.

1. Pipeline Gas and Storage Services

Bay State currently receives deliveries of pipeline gas and storage return gas from Algonquin and Granite State (Exhs. BSG-1, pp. 67-68, Table G-24, HO-SP-1, HO-SP-13). Algonquin delivers firm gas under rate schedules F-1, F-4 and WS-1 (id.). The Company stated that Algonquin also frequently offers additional gas during the winter under an excess WS-1 rate, and the Company included anticipated volumes of excess WS-1 pipeline gas in its normal and design year heating season supply plans (id.).

In addition, Algonquin provides storage services and interruptible return transportation under rate schedules STB and SS-III (id.). The Company maintains that, while the storage return transportation is "technically referred to as interruptible, it is almost akin to firm transportation" (Exh. BSG-1, p. 68). In support of this position, the Company stated that "since the seasonal volume provided under Algonquin's WS-1 tariff is only equivalent to 60 days at full daily contractual usage, the pipeline facilities which Algonquin has built to provide this service are in theory available on all other days for the transportation of STB and SS-III storage gas" (id.).

Granite State delivers firm gas from Tennessee to Bay State under rate schedule CD-1 (Exhs. BSG-1, p. 67, Table 24, HO-SP-1). The Company indicated that its maximum daily quantity ("MDQ") and annual volumetric limit ("AVL") under this rate schedule increased on December 7, 1988 as a result of Granite State's Portland Pipeline project (Exh. HO-SP-2). The Company also stated that Granite State occasionally has additional gas which it sells during both the heating and non-heating seasons on an interruptible basis under the CD-1 tariff (Exhs. BSG-1, p. 67, HO-SP-21). The Company included anticipated volumes of excess CD-1 gas in both the heating and non-heating seasons for its normal and design year supply plans (Exhs. BSG-1, Tables G-22N & G-22D, HO-SP-21).

Granite State also provides Bay State with two storage services. Storage is provided with: (1) Penn-York Energy Corporation under rate S-1, with associated return transportation via Tennessee under rates T-2 (interruptible) and T-4 (firm); and (2) Consolidated Gas Supply Corporation under rate GSS-1, with associated interruptible return transportation via Tennessee under rate T-1 (Exh. BSG-1, pp. 67-68, Table G-24, HO-SF-13). The Company's contracts for the pipeline gas and storage services identified above continue throughout the forecast period (Exhs. BSG-1, Table-24, HO-SP-1, HO-SP-13).

The Company stated that it is planning for one additional firm pipeline gas supply during the forecast period. This supply will consist of the purchase from Granite State of an additional 23,000 MMBtu per day to be delivered to the Company's Brockton division, and an additional 7,450 MMBtu per day to be delivered to the Company's Springfield division, both beginning in November 1991 (Exhs. BSG-3 (Molzan), p. 9, HO-SP-6). The Company stated that these volumes are part of a block of 35,000 MMBtu per day of gas for which Granite State already has a precedent agreement with Shell Canada (Exhs. BSG-1, pp. 71-72).[23]

The Company's plans for the transportation of these volumes changed during the course of this proceeding. The Company originally stated that 23,000 MMBtu per day would be delivered to the Company's Brockton division via the Champlain and Algonquin pipeline systems, and the remaining 7,450 MMBtu

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23/ The Company indicated that 4,550 MMBtu per day of the total 35,000 MMBtu per day has been allocated to Northern Utilities, Inc. (Exh. HO-SP-10; Tr. 2, pp. 30-32).

per day would be delivered to the Company's Springfield division via the Iroquois and Tennessee pipeline systems (Exhs. BSG-3 (Molzan), p. 9, HO-SP-6). However, in response to reported delays in the Champlain Pipeline project, on September 1, 1989, Granite State informed the Champlain Pipeline Company that it was terminating its agreement for the transportation of 23,000 MMBtu per day (Exhs. HO-SP-61, HO-SP-62). In addition, the Company presented an amended agreement between Granite State and Iroquois, dated September 15, 1989, which provides for delivery of the full 35,000 MMBtu per day of Shell Canada volumes by the Iroquois pipeline (id.).[24]

The Company also presented a precedent agreement dated October 10, 1989, between Granite State and Tennessee for transportation of 23,000 MMBtu per day from the Iroquois pipeline to the interconnection of Tennessee's and Algonquin's systems in Mendon, Massachusetts (Exh. HO-SP-61b). This agreement would require new facilities on Tennessee's system which also would have to be certificated by FERC (id.). Finally, the Company presented a precedent agreement dated October 16, 1989, between Granite State and Algonquin for transportation of 23,000 MMBtu per day from the interconnection of the Tennessee and Algonquin systems in Mendon, Massachusetts to Bay State's Brockton division (id.).

The Company stated that in order to receive the Shell volumes, the Iroquois project must be certificated by FERC, Granite State must receive an import license from the U.S. Department of Energy's Economic Regulatory Administration ("ERA"), and Granite State must get permission from FERC to increase its sales of gas to Bay State (Exh. HO-SP-7). The Company also stated that Granite State currently holds all

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24/ This agreement states, however, that should such an amendment subject Iroquois to additional comparative hearings at FERC, Iroquois would terminate the agreement (Exh. HO-SP-62). The agreement further states that such a termination would not effect the 7,450 MMBtu per day originally slated for delivery to Bay State's Springfield division (id.).

necessary Canadian approvals to export the gas (id., Exh. BSG-1, p. 71). Mr. Gulick stated that permission from the ERA to import the gas typically comes immediately after FERC approval of the sale of gas to the customer (Tr. 2, pp. 105-106). Mr. Gulick also indicated that the FERC approval process for the sale of the gas by Granite State to Bay State likely would take approximately three to four months, but should take no more than a year once the application is filed since no new Granite State facilities will be required (id., pp. 106-107). Finally, Mr. Gulick stated that construction of the Iroquois pipeline should take approximately 18 months after certification has been granted by FERC, and therefore, completion of construction of the Iroquois project is the critical item in receiving the volumes by November 1991 (id., p. 108). The Company indicated that it was not aware of any outstanding issue or regulatory process which would unduly delay the in-service date of the Iroquois project (Exh. HO-SP-7).

The Company also included anticipated spot purchases in its base case supply plans for both its normal and design year non-heating seasons (Exhs. BSG-1, p. 69, Table 22N, Table 22D, HO-SP-4, HO-SP-21, HO-SP-22). The Company stated that it would purchase gas on the spot market when it is less costly than firm pipeline gas and transportation is available (id.). The Company stated that these purchases primarily will serve interruptible markets, but will also supplant firm supplies if appropriate (id.). The Company indicated that its flexibility regarding such purchases has increased as most of its supply contracts are now free of take-or-pay requirements, and both Tennessee and Algonquin are open access transporters (Exh. BSG-1, pp. 69, 70, 86). The Company further stated that, since Granite State currently maximizes the spot gas opportunities on the Tennessee system, effectively passing those opportunites through to Bay State, Bay State itself has not utilized the open access provisions on Tennessee's system (Exhs. HO-SP-4, HO-SP-5, HO-SP-21).

Bay State stated that, as a result of increased flexibility in its supply and transportation arrangements, Granite State can now take gas from Tennessee at Mahwah, New Jersey, and Mendon, Massachusetts, thereby improving Bay State's ability to move gas supplies between Bay State's divisions (Exhs. BSG-1, p. 86, HO-SP-12). The Company stated that these new delivery points will allow a planned transfer of 6,000 MMBtu per day from the Springfield division to the Brockton division once the Iroquois deliveries of 7,450 MMBtu per day to the Springfield division begin (Exh. BSG-3 (Molzan), p. 10). In addition, the Company indicated that these delivery points will facilitate the delivery of up to 20,000 MMBtu per day of surplus gas from the Tennessee system to the Company's Brockton division on a best efforts basis by Algonquin (Exh. HO-SP-12).

As described above, the Company's base case supply plan includes a new increment of pipeline supplies. The Siting Council notes that a number of milestones not under the Company's control must be achieved before these new pipeline supplies are available for use in the Company's system. The Siting Council therefore must evaluate the adequacy of the Company's supply plan in the event of further changes or delays in the anticipated volumes. The Siting Council considers the following two contingencies associated with the Company's planned addition of Granite State's Shell Canada volumes: (1) a one year delay in delivery of the entire 30,450 MMBtu per day to November 1992, and (2) termination of the agreement for delivery of 23,000 MMBtu per day to the Company's Brockton division (see Sections III.E.1.b and III.E.2.b, below). The Siting Council also evaluates the impact of the addition of the Shell volumes on the cost of the Company's supply plan (see Section III.F.2.a, below).

2. Supplemental Supplies and Facilities

a. LNG

Bay State owns one LNG facility in Lawrence and leases three facilities from INLC in Ludlow, Marshfield and Easton

(Exh. BSG-1, Tables G-14, G-24). These facilities have a combined storage capacity of 1840.8 BBtu and a combined vaporization capacity of 121.2 BBtu per day (id.). The Company indicated that it plans to increase the vaporization capacity at the Easton facility from 35 BBtu per day to 50 BBtu per day on or about November 1, 1989 (Exh. HO-SP-53, Table G-16; Tr. 2, p. 65). The Company also indicated that it was considering an increase at the Marshfield LNG facility from 12 BBtu per day to 18 BBtu per day in the event that new pipeline supplies are delayed (id., BSG-1, Table G-24). The Company's supply plan also includes vaporization services from Providence during the first year of the forecast period (Exhs. BSG-1, Table G-14, HO-SP-13, HO-SP-15). The Company's supply plan calls for continued reliance on LNG from storage throughout the forecast period (Exh. BSG-1, Table G-22N, G-22D, G-23).

In its initial filing, Bay State stated that it anticipated that LNG would be available from DOMAC starting in the 1988-1989 winter season, and that the LNG would be delivered either in liquid form by truck or in vapor form through displacement on the Boston Gas Company, Tennessee and Algonquin systems (Exh. BSG-1, pp. 68-69). The Company later indicated that it was, in fact, purchasing LNG from DOMAC on a spot basis (Exh. HO-SP-18). The Company further stated during the course of this proceeding that, while DOMAC is actively marketing gas, and the Company is evaluating what a long-term arrangement with DOMAC would provide Bay State relative to other long-term supplies, the Company is not currently in the process of negotiating with DOMAC for any long-term LNG supplies (Exh. HO-SP-54; Tr. 2, pp. 69-70). Mr. Gulick stated that critical issues such as transportation and diversity of supply will have to be resolved before such an arrangement could be pursued (Tr. 2, p. 69). As of the close of the record in this matter, the Company's base case supply plan calls for LNG supplies from DOMAC to essentially cease following the addition of the new Granite State volumes from Shell Canada (Exhs. BSG-1, Table G-22N, G-22D, HO-SF-29).

b. Propane

Bay State stated that it contracts for propane on a short-term basis as needed from year to year (Exh. HO-SP-20). For the first year of the forecast period (1988-1989), the Company contracted with Petrolane Gas Service Limited and Sea-3 Inc. for a total of 1,200,000 gallons (id., Exh. BSG-1, Table G-22D/Backup). The Company owns seven propane facilities which have a combined storage capacity of 320.2 BBtu and a combined vaporization capacity of 118.1 BBtu per day (Exh. BSG-1, Table G-14). This vaporization capacity reflects an increase in capacity at the Company's Meadow Lane facility in the Brockton division from a maximum capacity of 22 BBtu per day to 30 BBtu per day (id., p. 2; Tr. 2, pp. 64-65). The Company's base case supply plan calls for decreased reliance on propane throughout the forecast period (Exhs. BSG-1, Table G-22N, Table G-22D, HO-SF-29). The Company stated that transportation of the propane will be by Transgas (Exh. BSG-1, p. 69). The Company stated that Transgas has "a long history of providing reliable, high-quality service in the transportation of liquid fuels" (id.).

c. NEA

Bay State's supply plan for the Brockton division includes a peaking gas supply starting in the winter of 1990-1991 (Exh. BSG-1, Table G-22N, G-22D). The Company stated that this gas will be made available to Bay State through an oil/gas swap with NEA's cogeneration facility in Bellingham (Exhs. BSG-1, p. 76, HO-SP-24, HO-SP-27). Under the terms of the contract, NEA, at Bay State's request, will burn No. 2 fuel oil in its facility for up to 30 full days during the period December 20 through February 28, thereby releasing its gas supply for Bay State's use (id., Exh. HO-SP-23). The supply will provide up to 60,000 MMBtu per day (id.). In return, the Company will pay NEA an annual charge and provide No. 2 fuel oil to NEA for its use (id.). The Company stated that the delivery of the gas to the NEA facility is dependent on the construction of pipeline facilities which are not yet certificated by FERC (Exhs. BSG-1, p. 76, HO-SP-24). In addition, the Company stated that both Algonquin and Tennessee might have to construct new facilities in order to deliver the gas to the Company's Brockton division (Exh. HO-SP-24). Mr. Gulick stated that these facilities should be in place within 12 to 15 months after Bay State requests them. However, Mr. Gulick also stated that he did not know how soon such requests would be made (Tr. 2, pp. 73-75; Exh. HO-SP-24). The Company stated that it did not believe that there were any factors which would delay the January 1, 1991 in-service date (Exhs. HO-SP-24, HO-SP-27).

As described above, the Company's supply plan includes a new source of supplemental supply and increases in capacity at both an existing LNG facility and an existing LP-air facility. In regard to the new source of supplemental supply from the oil/gas swap arrangement with NEA, the Siting Council notes that a number of milestones not under the Company's control must be achieved before this new supply is available for use in the Company's system. The Siting Council therefore must evaluate the adequacy of the Company's supply plan in the event of further changes or delays in the anticipated volumes. The Siting Council considers the contingeny of a one year delay in availability of the NEA volumes (see Sections III.E.1.b and III.E.2.b). The Siting Council also evaluates the impact of the addition of both this supply and the capacity increases at the existing propane and LNG facilities on the cost of the Company's supply plan (see Section III.F.2.b, below).

3. Conservation

The Company asserts that it includes conservation programs in its supply plan as a long-term supply (Bay State Brief, p. 40). As noted above, Mr. Ellis indicated that this is done indirectly through the sendout forecast, asserting that conservation "will automatically get built into the base-load heating increment; and that will automatically get translated forward into the gas-supply planning process" (Tr. 3, p. 70).

The Company stated that the conservation programs it will implement as part of its supply plan during the forecast period consist of: (1) customer information efforts; (2) a Company program intended to comply with its obligation, under the state's Residential Conservation Service ("RCS") program, to provide certain conservation services to residential customers; and (3) the use of Louisiana First Use Tax ("LAFUT") refunds for energy conservation loans (Exhs. BSG-1, pp. 77-78, BSG-3 (Davis), p. 2). The Company also stated that it has on-going efforts to identify and develop additional conservation programs for implementation in the future.[25]

Mr. Davis identified the Company's customer information program as essentially consisting of: (1) material accompanying bills; (2) pamphlets made available at home shows and at Bay State offices; and (3) telemarketing efforts (Tr. 4, pp. 10-12). Mr. Davis indicated that the information accompanying bills and included in pamphlets largely relates to conservation measures customers can perform themselves, while the telemarketing efforts are primarily directed at informing customers of the availability of the RCS audits (id.; Exh. BSG-3, Davis, p. 3). The Company did not indicate any energy savings resulting from this activity.

The Company stated that the RCS program is essentially the same as that run by Mass Save (Mass Save, a nonprofit Massachusetts organization, operates State-mandated conservation programs for a number of Massachusetts gas and electric utilities). The Company indicated that it withdrew from the Mass Save program in early 1988 and initiated its own program in order to maintain greater control over the costs associated with the program and to target conservation measures in Bay State's service territory (Exhs. BSG-1, p. 78,

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25/ The Siting Council reviews the Company's efforts to identify and evaluate conservation programs for future development in Section III.C.2. Here, the Siting Council reviews only programs included in the Company's base case supply plan.

BSG-3 (Davis), p. 3; Tr. 4, pp. 14-15). Mr. Davis stated that by running the program itself, it can better evaluate the conservation measures and integrate this information in future conservation decisions (Tr. 4, p. 78).

The Company stated that over 45,000 Bay State residential customers, approximately 25 percent of the total, have received an energy audit since the inception of the RCS program in 1980 (Exh. BSG-3 (Davis), p. 3). The Company did not identify energy savings associated with this program.

In regard to the Company's use of the LAFUT refunds, the Company stated that in 1983 Bay State used these funds to establish a revolving energy conservation fund. This fund is used to finance the installation of energy-saving measures in low and moderate income multi-family housing units (Exhs. BSG-1, p. 78, BSG-3 (Davis), pp. 3-4). The Company stated that it engaged CCC, a non-profit Massachusetts service company, to manage the fund (id.; Exh. HO-SP-29). Bay State stated that CCC has extensive experience in developing and providing design, engineering, and construction loans for energy improvements in multi-unit buildings (Exhs. BSG-3 (Davis), p. 4, HO-SP-29). The Company stated that the loans from this fund are repaid using the cash flow from the energy savings (Exh. HO-SP-29).

The Company asserted that these loans have resulted in "significant energy savings" (Exh. BSG-1, p. 78). In support of this assertion, the Company presented a CCC progress report indicating that since 1983, CCC has issued loans to 20 customers representing over 600 individual apartments (Exh. HO-RR-8; Exhs. BSG-3 (Davis), p. 4, HO-SP-30). The report indicates that CCC estimates total energy savings for all the projects as 215,000 therms per year (id.). Mr. Davis stated that he had verified the estimate of energy savings by comparing, on a weather normalized basis, the energy use during the twelve months prior to the installation of the conservation measures at three of the projects with the energy use during the twelve months after the installation (Tr. 4, pp. 25-26). The Company stated that, as a result of the success of this program, it intends to increase the size of this program during the forecast period through the investment of an additional $1.5 million subject to MDPU approval.

The Company's supply plan does not directly include any resources from conservation programs. The Siting Council evaluates the impact of this approach on the cost of the Company's supply plan (see Section III.F.2.c, below). The Siting Council also evaluates the impact of the Company's specific decisions regarding implementation of conservation programs in Section III.F.2.c, below.

4. Load Management

The Company stated that its load management plans for the forecast period consist of strategic load growth programs. The Company stated that this type of program traditionally has consisted of interruptible customers whose gas supply was terminated during the first part of November and resumed during the latter part of March (Exh. BSG-3 (Ellis), p. 5). The Company stated that it recently has initiated a "second generation" interruptible sales program called the "Marginal Interruptible Sales Program" (id.). The Company stated that this program is designed to extend the benefits of interruptible sales into the winter period. The program accomplishes this goal by enabling the Company to sell any gas supply remaining after the needs of its firm customers are met to its dual fuel interruptible customers on a day-to-day basis throughout the winter, if the customer is willing to pay a price which exceeds the marginal cost of that supply (id.). The Company stated that during the 1987-1988 winter it sold over 62,700 MMBtu to interruptible customers as a result of its marginal sales program (id., p. 6).

The Company stated that underground storage injections and liquefaction, while they have the effect of shifting load from the winter to the summer, should really be considered to be strategic load additions (Exh. BSG-1, p. 83). The Company also stated that it is pursuing additional non-traditional strategic load additions such as gas air-conditioning, and has initiated a compressed natural gas vehicle pilot program using Company-owned vehicles in its Springfield division (Exhs. BSG-1, p. 83, HO-SP-42).

In sum, the Company stated that it currently has in place for the forecast period strategic load growth programs which enable the Company to manage up to 60 percent of the Company's current firm daily pipeline purchase obligations (id.). The Company also stated that its traditional interruptible market in 1987 resulted in an off-peak market equivalent of over 54,251 MMBtu per day (id.). The Company asserted that this amount, in combination with its storage capability, represents non-peak loads of up to 85,251 MMBtu per day served by low-cost, high reliability pipeline supplies (id.). The Company stated, however, that 16,500 MMBtu per day of these supplies are associated with interruptible transportation making them potentially unavailable on the coldest winter days (Exh. HO-SP-40).

The Company did not include a strategic load elimination program in its supply plan for the forecast period. Mr. Ellis stated that after evaluating the various costs associated with such a program, the Company determined that, for the 1988-1989 winter, such a program would not be cost effective (Exh. BSG-3 (Ellis), p. 10). The Company did indicate, however, that it planned to include a load shedding tariff in its current MDPU filing to allow the Company to proceed with a load elimination program in future years of the forecast period if it was cost effective (Exh. BSG-1, p. 82).

The Company also did not include any load shifting programs in its supply plan for the forecast period. The Company stated, however, that it was including a seasonal base rate structure in its current MDPU filing to encourage customers to "make appropriate decisions regarding the selection of gas burning equipment and the utilization of alternate fuels" (Exh. BSG-3 (Ellis), p. 9).

As described above, the Company's base case supply plan does not include resources made available through the implementation of load elimination programs. The Siting

Council evaluates the impact of the Company's decisions regarding the implementation of specific load management programs on the cost of the Company's supply plan in Section III.F.2.d, below.

E. 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 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 Year and Design Year Adequacy

a. Base Case Analysis

In normal and design year planning, Bay State must have adequate supplies to meet several types of requirements. Bay State's primary service obligation is to meet the requirements of its firm customers. 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, Bay State also supplies gas to its interruptible customers.

In its initial filing, the Company presented its supply plans for meeting its forecasted normal year and design year sendout requirements throughout the forecast period for the Company as a whole (Exh. BSG-1, pp. 88-91, Tables G-22N, G-22D). In addition, the Company presented its plans for meeting sendout requirements on a division-specific basis (with the Lawrence and Springfield divisions combined due to inter-division flexibility) (Exh. HO-SF-29). The Company's supply plans include optional sales for resale requirements in design years, and anticipated interruptible sales during both normal and design years in all divisions (id.).

The Company stated that the change in the anticipated volumes and delivery date for the new pipeline supplies would result in a net increase, relative to the original supply plan, in both the Brockton and combined Springfield and Lawrence divisions beginning in the winter of 1991 (Exh. BSG-3 (Molzan), p. 10).[26] The Company did not provide updated tables, but stated that the increases in the heating season supply plans would be 1,000 MMBtu per day in the Brockton division and 1,450 MMBtu per day in the combined Springfield and Lawrence divisions (id.). The Company further stated that the Company would delay reduction of DOMAC and WS-1 excess purchases for the Brockton division by one year, and would slightly increase annual purchases of Granite State interruptible supplies and use of LNG from storage for the combined Springfield and Lawrence divisions (id., p. 11). In addition to DOMAC and WS-1 excess, the Company's supply plan for its Brockton division includes supplies from the NEA project during both normal and design year heating seasons and transfers of LNG from the Springfield division during the design year heating season (Exh. HO-SF-29). As noted previously, the Company's base case supply plan does not include any anticipated gas savings due to specific conservation or load management programs. The Company's design year supply plans for the Brockton and combined Springfield and Lawrence divisions are summarized in Tables 2 and 3.

The Siting Council notes that the Company also has available to it both propane and LNG in storage in excess of planned use during normal and design heating seasons, and has

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26/ This net increase assumes a transfer of 6,000 MMBtu per day from the combined Springfield and Lawrence divisions to the Brockton division during the heating season (Exh. BSG-3 (Molzan), p. 10).

the ability to reduce or fully eliminate interruptible sales as needed to meet its firm sendout requirement.

i. Parties' Arguments

MMWEC argues that the Siting Council should not approve the Company's supply plan, and asserts that the supply plan fails to "demonstrate an adequate supply of gas" (MMWEC Brief, pp. 6, 9). In support of its position, MMWEC states that Bay State uses spot gas for sales to interruptible customers, and that Bay State did not provide forecasts of future spot gas purchases, or of the volumes of gas which it will have available for interruptible sales (id., p. 7). Consequently, MMWEC asserts that the Company "has not demonstrated that it will have adequate supplies of gas, in excess of firm requirements, to be able to serve MMWEC with the forecasted 10,500,000 MMBtu per year" (id., p. 6). Finally, MMWEC argues that "faulty planning for interruptible sales has an adverse affect on both the purchasers of the interruptible gas and the firm customers of Bay State" and that this prevents Bay State from meeting the Siting Council's objectives regarding load management (id., pp. 8, 9).

In response to MMWEC's arguments, Bay State reasserts its earlier arguments (see Section II.E.2, above) regarding the Company's lack of an obligation to serve interruptible customers (Bay State Reply Brief, p. 3). The Company stated that "the primary focus of its supply plan is to meet the requirements of its firm customers" and that "[t]o the extent that available supplies exceed the requirements of the Company's firm customers, those excess supplies will be made available to interruptible customers who desire to substitute gas for their alternate fuel" (id.). The Company further stated that "[i]f additional interruptible demand exists, Bay State will use best efforts to satisfy that unserved demand by acquiring additional supplies on the spot gas market" (id.). In regard to MMWEC's argument related to Bay State's commitment to the Siting Council's load management objectives, Bay State stated that it "views interruptible sales as a valuable vehicle to reduce gas costs to its firm customers as well as an integral component of its load management program" (id., p. 4). However, the Company also stated that such recognition "cannot be turned into a requirement that Bay State develop a supply plan which ensures that Bay State will meet the needs of all of its interruptible customers with the same degree of reliability that Bay State meets the needs of its firm customers" (id.). Finally, Bay State argues that "it is ludicrous, in light of the record in this proceeding and the statutory requirements, for MMWEC to claim that Bay State's supply plan is deficient because Bay State has not proven that adequate supplies will be available for projected interruptible sales" (id., p. 5).

ii. Analysis

In this case, the Company's supply plan changed somewhat during the course of the proceeding. The Company, however, has provided the Siting Council with the basic elements of its plan, as well as sufficient information to establish that its revised base case plan ensures that the Company's firm sendout requirements in each division will be met throughout the forecast period.

In reviewing a gas company's supply plan for adequacy, the Siting Council focusses on the company's ability to meet the needs of its firm customers. In past decisions, the Siting Council has repeatedly emphasized this focus. 1988 ComGas Decision, 17 DOMSC at 36; 1987 Bay State Decision, 16 DOMSC at 313; 1987 Boston Gas Decision, 16 DOMSC at 239. While MMWEC is correct in noting the Siting Council's interest in achieving load management objectives, this interest is the result of the Siting Council's mandate to ensure a least-cost, least environmental impact supply to firm customers. Clearly, the Siting Council has no requirement that a gas company provide proof of its ability to satisfy the needs of its interruptible customers. Therefore, the Siting Council rejects the arguments of MMWEC regarding the adequacy of Bay State's supply plan.

Accordingly, the Siting Council finds that the Company has established that its revised normal year and design year base case supply plans are adequate to meet the Company's forecasted firm sendout requirements, off-system sales and storage refill requirements on a division-specific basis throughout the forecast period.

b. Contingency Analysis

As described above, the Company's revised base case supply plan includes supplies which are not yet in place and which require both permitting and construction activities outside the Company's control (see Sections III.D.1 and III.D.2.c, above). The Siting Council therefore reviews the adequacy of the Company's supply plan in the event that one of the following contingencies occurs: (i) a one year delay in delivery of the entire 30,450 MMBtu per day to November 1992; (ii) termination of the agreement for delivery of 23,000 MMBtu per day to the Company's Brockton division; and (iii) a one year delay in availability of the NEA volumes.

i. One Year Delay in Iroquois Project

Bay State's revised supply plan calls for an in-service date of November 1991 for the Iroquois project and associated deliveries of the additional 30,450 MMBtu per day from Granite State. In the event that delivery of these supplies is delayed until November 1992, and if all other resources remain available to the Company, the Company would experience a resource deficiency in meeting forecasted firm sendout in the 1991-92 design year heating season of approximately 2,430 BBtu (18 percent) in the Company's Brockton division. The Company's would experience no resource deficiency in its combined Springfield and Lawrence divisions. See Tables 2 and 3.

In the event of such a delay, Bay State stated that during summer 1992, the Company would rely on spot gas, contract gas or reduced interruptible sales to ensure that its storage volumes were full prior to the beginning of the heating season (Exh. BSG-3 (Gulick), p. 14). During the winter, the

Company stated that it would "increase the firm utilization of contract and storage gas, and rely more heavily on supplemental fuels" (id.). Mr. Ellis stated that the Company's options also included reactivation of a liquefaction plant in Ludlow, and increased use of propane, and LNG from DOMAC (Tr. 2, pp. 119-120). Mr. Molzan stated that in the event DOMAC and WS-1 excess volumes were no longer available, the Company would increase the amount of firm propane under contract for the winter period (Tr. 4, p. 101). Mr. Molzan also stated that, in the past, the Company has purchased as much as 30 times the amount of propane under contract during the 1988-1989 period in a single winter, and therefore increased propane purchases would be a viable option (id.).

The Siting Council finds that an action plan involving a combination of the increased use of supplies from the NEA project (if available), continued purchases of DOMAC and WS-1 excess, and if necessary, use of the Company's propane in storage would allow the Company to meet deficiencies in all divisions.

Accordingly, the Siting Council finds that Bay State has an action plan which would allow it to meet the resource deficiency during the 1991-92 design year in the event of a one year delay in the Iroquois project and, therefore, has adequate resources to meet forecasted firm sendout requirements in all divisions in the event such a contingency occurs.

ii. Termination of Transportation Agreement for 23,000 MMBtu per day

As noted previously, the Company's revised supply plan calls for 30,450 MMBtu per day in new pipeline volumes to be imported via the Iroquois Pipeline, and transported to the Company's service areas through the Tennessee and Algonquin pipeline systems. The Company's revised supply plan requires that the 23,000 MMBtu originally slated for transportation via the Champlain project now be included in the final Iroquois and Tennessee projects certificated by FERC. However, the transportation of 23,000 MMBtu per day to the Brockton division is subject to cancellation if these new transportation plans prompt comparative hearings at FERC.[27] In the event of cancellation of these new transportation arrangements for the 23,000 MMBtu per day for the Brockton division, and if all other resources remain available to the Company, the Company would experience a resource deficiency in its Brockton division in the design year heating season of approximately 1527 BBtu (11 percent) in 1991-92 and 1486 BBtu (11 percent) in 1992-93 (see Table 2). The Company's supply plan for the heating season in the combined Springfield and Lawrence divisions would remain essentially unchanged. The Company noted that during the non-heating season, such a reduction in new supplies would lead to a reduced ability to serve interruptible loads.

The Company stated that, should transportation arrangements for the volumes be cancelled, the Company would seek alternative import options through either Niagara Falls or points further west (Exh. BSG-3 (Gulick), p. 14). Mr. Gulick stated that this option would require construction of new facilities by both Tennessee and Transcanada (Tr. 2, p. 127). The Company stated that a second option available to it would be purchases from DOMAC, which Mr. Gulick stated could be arranged "fairly quickly" as no new facilities would be required and transportation would be effectuated through displacement (id.; Exh. BSG-3 (Gulick), p. 14). The Company also indicated that it would likely increase the capacity at the Marshfield LNG facility in the event that increased pipeline supplies were not available (Exh. HO-SP-53, Table G-24).

The Siting Council notes that the Company's action plan for addressing a one year delay in all Iroquois volumes

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27/ Delivery of the 7,450 MMBtu per day to the Company's Springfield division is not affected by the revised transportation arrangements and would not be impacted in the event of this contingency.

described in contingency (i) above could be utilized here as well on an annual basis to meet this resource deficiency until such time as other transportation arrangements for the Shell Canada volumes could be developed, or arrangements for another firm source were completed.

Accordingly, the Siting Council finds that Bay State has an action plan which would allow it to meet the resource deficiency during 1991-92 and beyond in the event of a cancellation of the new pipeline volumes by 23,000 MMBtu per day in its Brockton division and, therefore, has adequate resources to meet forecasted firm sendout requirements in all divisions in the event such a contingency occurs.

iii. One Year Delay in NEA Project

Bay State stated that it is planning to utilize gas from the NEA facility starting in January 1991. Both the Company's normal and design year supply plans include 90 BBtu from this source to be used during the 1990-1991 heating season in the Company's Brockton division. In the event of a one year delay in the start date for this project, and if all other resources remain available to the Company, the Company would not experience a resource deficiency during the 1990-1991 forecast year (See Table 2).

Accordingly, the Siting Council finds that the Company's base case supply plan is adequate to meet forecasted firm sendout requirements in the event of a one-year delay in the NEA project.

2. Design Day Adequacy

a. Base Case Analysis

Bay State 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 peak day.

Bay State presented its base case design day supply plan in support of its assertion that it has adequate resources to meet forecasted firm design day sendout requirements for the Company as a whole and for each division (Exhs. BSG-1, p. 93, Table G-23, HO-SF-28; Bay State Brief, pp. 22-23). These plans were revised, as noted previously, during the course of the proceeding to reflect the increased volumes and delayed delivery date of the new pipeline supplies. These revised plans indicate that the Company has adequate resources to meet its forecasted firm design day sendout requirements on both a division and Company-wide basis throughout the forecast period. The Company's design day base case supply plan includes volumes from the NEA project and increased capacity at the Easton LNG facility in addition to the new pipeline supplies. As described above, the Company's design day supply plan does not include anticipated gas savings from conservation or load management programs. The Company stated that it maintains a 20 percent reserve margin in supplemental capacity required to meet design day requirements (Exh. HO-SP-58).

Accordingly, the Siting Council finds that Bay State has established that its base case supply plan is adequate to meet forecasted firm design day sendout requirements for all its divisions in all years of the forecast period.

b. Contingency Analysis

In the event of either: (i) a one year delay in the Iroquois project; (ii) cancellation of 23,000 MMBtu per day to the Brockton division; or (iii) a one year delay in the NEA project, the Company would not be subject to a design day resource deficiency in any of its divisions (See Tables 4 and 5).

Accordingly, the Siting Council finds that the Company's design day supply plan is adequate to meet forecasted firm sendout requirements in the event of either: (i) a one year delay in the Iroquois project; (ii) cancellation of transportation arrangements for 23 BBtu per day to Brockton; or (iii) a one year delay in the NEA project.

3. Cold-Snap Adequacy

In its last decision, the Siting Council ordered Bay State to submit a cold-snap analysis as part of its next filing. 1987 Bay State Decision, 16 DOMSC at 32. The Siting Council has defined a cold-snap as a prolonged series of days at or near design conditions. 1989 Fitchburg Decision, EFSC 86-11(A), p. 48; 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. 1988 ComGas Decision, 17 DOMSC at 137; 1987 Berkshire Decision, 16 DOMSC at 79; 1986 Fitchburg Decision, 15 DOMSC at 58, 61; 1987 Bay State Decision, 16 DOMSC at 47.

a. Description

In response to the Siting Council's order in the last decision, the Company presented a cold-snap analysis based on an actual 24 day occurrence from December 22, 1980 through January 14, 1981 (Exh. BSG-1, Appendix I, p. 1). The Company stated that it "chose a recent actual period that stands out as a severe cold-snap in recent history" (Exh. HO-SP-43, p. 1). The Company argues that its use of an actual period of severe weather is a realistic standard which is appropriate for judging its ability to supply the firm needs of its customers (Bay State Brief, p. 25). In addition, the Company argues that the Siting Council recently has accepted the use of actual severe weather experience for the development of a cold-snap preparedness study (id., p. 24).

The Company supported its choice by stating that "this period holds more meaning than simply choosing the coldest 24-day period because the absolute degree day total over a time period is not as important in supply planning as the distribution of these levels with[in] the period" (id.). The

Company stated that the distribution of degree days within a period is important in relation to the requirements for supplemental fuels above various degree day levels (id., pp. 1, 2). Consequently, the Company asserts that it would be difficult to develop mathematically a cold-snap standard which would reflect the true difficulties associated with a real period of severe weather (id., p. 3; Exh. BSG-3 (Gulick), pp. 11-12). In regard to the time period assumed for the cold-snap, Mr. Gulick stated that "generally colder weather occurs from the second week in December to the end of the second week of February" (Tr. 2, pp. 141-142). Mr. Gulick asserted that the Company would be able to meet its cold-snap standard during any part of the winter, stating that the Company plans its use of supplementals in anticipation of potential severe weather in the latter part of a winter (id., p. 142).

The Company presented its plan for meeting its cold-snap standard during the 1988-1989 winter on a Company-wide basis (Exh. BSG-1, Appendix I). While the Company did not present specific plans for meeting its cold-snap standard on a division-specific basis, Mr. Gulick stated that the Company anticipated no problems in meeting its division-specific requirements during a cold-snap due to the Company's ability to move supplies between divisions as needed (Tr. 2, pp. 155-156). The Company stated that in modeling the sendout for its cold-snap analysis, it made the following assumptions:

> "(1) LNG and LP inventories were full;
> (2) DOMAC LNG vapor and WS-1 excess were available on an interruptible basis;
> (3) a declining percentage of best-efforts storage transportation, DOMAC LNG vapor and WS-1 excess were available up to a 78 EDD; and
> (4) no interruptible sales were made."

(Exh. BSG-1, Appendix I, p. 1).

The Company stated that these assumptions are realistic based on the Company's experience with these supplies. In regard to the first assumption, Mr. Gulick stated that LP inventories can be maintained at a full level on essentially "an around-the-clock basis" (Tr. 2, p. 150). In addition, Mr. Gulick stated that the Company's LNG inventories would normally be full any time through the middle of January, and, in addition, the Company would be able to refill those inventories on warmer days throughout the winter (id., p. 153). Mr. Ellis added that due to the Company's current pipeline supply sources, the volume of both propane and LNG the Company has in storage is likely to be greater than what the Company would use over an entire winter (id., pp. 151-152). Further, in regard to transportation requirements for propane and LNG, the Company stated that no LNG transportation would be needed during the cold-snap, and any propane transportation required both before and during the cold-snap would be accomplished through the Company's own fleet of trucks and by trucking firms with long histories of reliable service to Bay State (Exh. BSG-1, p. 2). According to Bay State, any propane purchases which had to be made would be from facilities in close proximity to the Company's propane plants, thereby minimizing transportation concerns (id.). Mr. Ellis stated, however, that, in the future, should the Company's reliance on propane increase substantially, contracts and transportation requirements would have to be adjusted accordingly, and the Company might have to resort to propane purchases on the open market during a cold-snap (id., pp. 152-153). In regard to the second and third assumptions concerning the availability of DOMAC LNG vapor, WS-1 excess, and storage transportation on an interruptible basis, Mr. Gulick stated that on warmer days these supplies and transportation have historically been available and, therefore, these represent reliable assumptions (id., p. 154).

b. Analysis

i. Compliance with Order Three

In the 1987 Bay State Decision, the Siting Council ordered Bay State to "submit a cold-snap analysis in its next filing" (16 DOMSC at 326). The Siting Council ordered such an analysis after determining that the Company's ability to meet a cold-snap was dependent upon proper management of its propane and LNG supplies as well as its ability to transport necessary supplies to its facilities (id.). In this proceeding, the Company has responded to the Siting Council's order and presented a detailed analysis of its cold-snap supply plan.

Accordingly, the Siting Council finds that Bay State has fully complied with Order Three of the previous decision.

ii. Cold-Snap Adequacy

The Siting Council finds that the Company's choice of a cold-snap standard based upon an actual period of extreme weather is reasonable. Additionally, the Company's choice of a historic cold-snap which is generally recognized as having led to supply constraints in the region is appropriate and represents a sound basis for supply planning. Accordingly, the Siting Council finds that the Company's choice of a cold-snap standard is appropriate for a company of its size and resources.

The Siting Council also finds that the Company has established that it has an adequate supply plan to meet its firm sendout requirements in the event of a cold-snap during the first year of the forecast period. The Siting Council notes that the Company has sufficient propane inventories such that purchases during a cold-snap period should not be necessary. In addition, the Company's available LNG storage volumes should be sufficient to cover the Company's requirements in the event that interruptible pipeline supplies or transportation are not available in the quantities assumed.

The Siting Council notes, however, that the Company's future ability to meet firm sendout requirements depends on: (1) its continued ability to ensure full storage volumes; and (2) pipeline and overland transportation availability. This ability may be markedly affected by the timing of future increases in firm pipeline supplies to New England generally and Bay State specifically. Consequently, the Company should be prepared in future forecast reviews to establish the continued adequacy of its cold-snap supply plan in light of current supply scenarios.

The Siting Council has found that the Company has complied with Order Three from the last decision. The Siting Council also has found that the Company has developed an appropriate cold-snap standard, and that the Company has established that its supply plan is adequate to meet its firm sendout requirements in the first year of the forecast period in the event a cold-snap occurs.

Accordingly, the Siting Council finds that Bay State has established that it has adequate resources to meet its firm sendout requirements under cold-snap conditions during the first year of the forecast period.

4. Conclusions on the Adequacy of the Supply Plan

The Siting Council has found that the Company has established: (1) that its revised normal year and design year base case supply plans are adequate to meet the Company's forecasted firm sendout requirements, off-system sales and storage refill requirements on a division-specific basis throughout the forecast period; (2) that Bay State has an action plan which would allow it to meet the resource deficiency during the 1991-92 design year in the event of a one year delay in the Iroquois project and, therefore, has adequate resources to meet forecasted firm sendout requirements in all divisions in the event such a contingency occurs; (3) that Bay State has an action plan which would allow it to meet the resource deficiency during 1991-92 and beyond in the event of a cancellation of 23,000 MMBtu per day in new pipeline supplies for its Brockton division and, therefore, has adequate resources to meet forecasted firm sendout requirements in all divisions in the event such a contingency occurs; and (4) that the Company's base case supply plan is adequate to meet forecasted firm sendout requirements in the event of a one year delay in the NEA project.

The Siting Council also has found that Bay State has established that its base case supply plan is adequate to meet forecasted firm design day sendout requirments for all its divisions in all years of the forecast period. In addition, the Siting Council has found that the Company's design day base case supply plan is adequate to meet forecasted firm sendout requirements in all divisions in the event of either (1) a one year delay in the Iroquois project; (2) cancellation of transportation arrangements for 23,000 MMBtu per day to the Brockton division; or (3) a one year delay in the NEA project.

Further the Siting Council has found that Bay State has fully complied with Order Three of the previous decision. The Siting Council also has found that the Company has established that it has an adequate supply plan 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 Bay State has established that it has adequate resources to meet its firm sendout requirement throughout the forecast period.

F. 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. 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; see 1989 NEES Decision, 18 DOMSC at 337. A gas company must establish that application of its supply planning process -- including adequate consideration of conservation and load management 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 prior to selection of major new resources for their supply plans. 1989 Fitchburg Decision, EFSC 86-11(A), p. 52; 1987 Bay State Decision, 16 DOMSC at 319; 1986 Gas Generic Order, 14 DOMSC at 100-102.

2. Supply Cost Analysis

Bay State has included in its base case supply plan a new long-term pipeline supply -- the Shell volumes -- and both a new source of supplemental supply and incremental supplemental capacity (see Sections III.D.1 and III.D.2, above). In addition, the Company has made cost-based decisions regarding the implementation of conservation and load management programs in the forecast period (see Sections III.D.3 and III.D.4, above).

The Siting Council recognizes that it has previously reviewed Bay State's plan to obtain additional CD-1 volumes from Granite State, volumes that Granite State intended to purchase from Shell (see 1987 Bay State Decision, 16 DOMSC 311-312, 322-323). At the time of that decision, however, a certain volume of gas was to be transported to Bay State solely on Granite State's Portland pipeline. With the advent of the "Open Season" process, the volume of CD-1 gas the Company could receive changed as additional transportation became available. It is in light of these changes that we review Bay State's planned, additional, CD-1 pipeline supplies.

The overall supply planning process the Company used in making supply decisions such as these and the impact of the decisions on the adequacy of the Company's supply plan have been reviewed above (see Sections III.C and III.E, above). Here, the Siting Council reviews the Company's actual application of its supply planning process in making specific supply decisions to determine if application of that process resulted in a least-cost resource plan.

a. Shell Volumes

The Company asserts that the new pipeline supply anticipated during the forecast period from Granite State represents a least-cost addition to the Company's supply plan (Bay State Brief, p. 32). In support of this position, the Company identified the range of options available to it and described how it evaluated them in reaching its decision to add this supply to its base case plan (see, also, 1987 Bay State Decision, 16 DOMSC at 322-323).

The Company stated that it viewed FERC's "Open Season" process as "critical to obtaining its next increment of baseload gas supplies" (Exh. BSG-3 (Gulick), p. 15). Mr. Ellis stated that the Company also viewed the "Open Season" process as an opportunity to add significant diversity to its transportation arrangements (Tr. 3, pp. 83-86). Mr. Ellis noted that the "Open Season" process provided the Company with transportation options only, and, because no new baseload pipeline gas supplies are currently being offered in the Northeast, gas companies had to locate gas supplies on their own for inclusion in the "Open Season" transportation projects (Tr. 2, pp. 33, 41-42).

The Company indicated that it was presented with the choice of (1) purchasing its previously arranged gas supply -- the Shell volumes -- through Granite State and formulating its own transportation arrangements, or (2) pursuing a new source of supply and arranging for its transportation. The Company indicated that the primary criterion considered by the Company in comparing the Shell volumes to other options was timing. Mr. Gulick testified that "the completeness of the Canadian regulatory permits supporting" the Shell volumes relative to other supplies was significant (Exh. BSG-3 (Gulick), p. 15). Mr. Gulick further stated that pursuing another source of pipeline supply "would have set back the supply development process a number of years," and indicated that such a setback would have impacted the ability of the Company to utilize the "Open Season" process to acquire transportation for new supplies (id.).

In addition to timing, the Company stated that price was an important criterion in the evaluation of the Shell volumes relative to other supplies. The Company asserted that the price of the Shell volumes was lower than both domestic and other Canadian supply options, and, in fact, would be essentially the same as the Company's current lowest priced gas supplies (id., p. 16; Tr. 2, pp. 45-46; Bay State Brief, pp. 30-32). Mr. Ellis stated that the pricing formula of the Shell volumes is "designed to create a price at the burner tip which will compete with and follow the cost of alternate fuels" including competing gas supplies (Tr. 3, pp. 24-25). Mr. Ellis further stated that domestic supply contracts, by contrast, are "very price-insensitive" and stated that the Company knew what domestic supplies would likely cost based on the last increments of F-2, F-3 and F-4 gas purchased by the Company (id.; Tr. 2, pp. 40-42, 45). In regard to other Canadian supply options, Mr. Ellis stated that the Company doubted it could secure supplies from a new Canadian source at a lower price than the Shell volumes (Tr. 2, p. 46).

Mr. Ellis further stated that the Company was concerned that if it went in search of other supplies, Shell potentially would have backed out of the deal (Tr. 2, pp. 46-47). Mr. Ellis also asserted that competition for Canadian gas supplies is very intense and other gas purchasers have found it increasingly difficult to secure Canadian gas supplies at desirable prices (Tr. 3, pp. 25-28).

In regard to transportation arrangements for the Shell volumes, Bay State stated that the only available arrangements were the pipeline proposals submitted to FERC as part of the "Open Season" process. During the course of this proceeding, the Company's plans changed from transportation on Champlain alone, to transportation on a combination of the Champlain and Iroquois projects, and finally to transportation on the Iroquois project only. The Company described the bases of its decisions and asserted that the transportation arrangements were developed to provide the lowest cost transportation while maximizing the Company's ability to utilize the supplies throughout its service territory (Exhs. BSG-1, pp. 73-75, HO-SP-11; Tr. 2, pp. 32-34).

The Siting Council notes that the Company's plans for new pipeline supplies and transportation during the forecast period have become more definite during the course of this proceeding. As such, the Siting Council has been able to witness the application of the Company's planning process as it occurred. Here, the unique nature of the "Open Season" process and the developed status of the Shell volumes presented Bay

State with an unusual opportunity. In finalizing its arrangement to purchase Shell volumes rather than pursuing other options, the Company applied its planning process appropriately and satisfied several of its important planning criteria -- timing, ability to transport, and cost.

The Siting Council notes, however, that the Company did not conduct a cost study comparing the Shell volumes to other pipeline and non-pipeline options, a step which we have found to be vital in making a resource decision. Because resource decisions should not be made without the benefit of a cost study comparing alternative options, the Siting Council has required gas companies to establish that they have completed comprehensive cost studies prior to selection of major new resources for their supply plan. 1989 Fitchburg Decision, EFSC 86-11A, at 52-53; 1988 ComGas Decision, 17 DOMSC at 65-66; 1987 Bay State Decision, 17 DOMSC at 34; 1987 Boston Gas Decision, 16 DOMSC at 47; 1986 Gas Generic Order, 14 DOMSC at 100-102.

While a cost study would have been appropriate here, we find that the Company conducted an analysis of the Shell pricing formula, as well as an analysis of the cost of existing domestic pipeline supplies. In view of these analyses and the Siting Council's finding in the 1987 Bay State Decision that certain Shell volumes were a least-cost addition to the Company's supply plan, the Siting Council finds that Bay State properly applied its supply planning process in reaching a decision on the Shell volumes and that the addition of the Shell volumes contribute to a least-cost plan.

The Siting Council notes, however, that in the future, when large increments of baseload pipeline supplies are added to the Company's supply plan, the Company will be required to establish and fully document that it has identified and thoroughly evaluated, including completion of cost studies, a full range of options including conservation and load management in applying its supply planning process.

b. Supplemental Supply and Capacity Increases

i. NEA

The Company stated that it views the oil/gas swap with NEA as a peaking supply (Exh. BSG-1, pp. 76-77). Mr. Gulick stated that a primary reason for pursuing this supply rather than other traditional supplemental supplies, was that it provides the Company with a large source of supplemental supply with pipeline reliability for a "very economic demand charge" (Tr. 2, pp. 81-82). The Company asserted that this supply is "cheaper than any alternative supplemental capacity that Bay State could build" (Exh. BSG-1, p. 77). In support of this assertion, the Company compared the demand and commodity costs of the NEA oil/gas swap with (1) the costs associated with increased capacity at the Meadow Lane propane facility, and (2) the costs of additional capacity at the Easton LNG facility (Exh. BSG-1, p. 77; Tr. 3, pp. 17-21). The Company stated that these analyses show that while the commodity costs associated with the oil/gas swap are similar to costs for both propane and LNG, the demand costs per BBtu associated with the oil/gas swap are significantly lower than the demand costs per BBtu associated with the increases in capacity at the Meadow Lane and Easton facilities (id.). The Company also noted that the size of the supplemental supply generated through the oil/gas swap -- up to 60 BBtu per day -- is significantly larger than potential capacity from incremental increases at any existing facilities. In addition, the Company indicated that since the NEA oil/gas swap provides pipeline volumes, it is not subject to the operating constraints associated with the use of propane or to reliability concerns related to both LNG and LP-air facilities (Exh. BSG-3 (Gulick), pp. 13-14; Tr. 2, p. 81, Tr. 3, pp. 19-21).

The Siting Council notes that the NEA oil/gas swap represents a unique and innovative supply option. In deciding to add the NEA volumes to its base case supply plan, the Company applied its planning process appropriately. The Company satisfied several of its important planning criteria -- diversity of supply, reliability and cost -- in making its decision. While the Company did not present a detailed explanation of the process it followed in identifying this option and evaluating it against other supplies, the Siting Council is satisfied that the merits of this supply option were appropriately weighed against other options.

Accordingly, the Siting Council finds that Bay State properly applied its supply planning process in reaching a decision on the NEA oil/gas swap and that the addition of the NEA volumes contribute to a least-cost plan.

ii. Facility Upgrades

Mr. Ellis stated that the Company's decision to increase the capacity at the Company's Meadow Lane and Easton facilities by 10 BBtu and 15 BBtu per day respectively was made in response to a need for short-run additional supplemental gas capacity until volumes from the NEA oil/gas swap were available in 1990 (Tr. 3, pp. 15-16, 92-94, 96-97). Mr. Ellis asserted that these increases were essentially the only options available to the Company which would meet the near-term need for peak supplies. Mr. Ellis supported this assertion by stating that construction of new facilities was too difficult and time consuming, increased use of firm pipeline supplies was too costly, DOMAC volumes were not yet firm, and other options would take too long to develop (id.). The Company did not compare these increases to implementation of conservation or load management programs.

Bay State's decision to increase capacity at both the Meadow Lane propane facility and the Easton LNG facility reveals some of the problems in the Company's supply planning process addressed by the Siting Council in Section III.C, above. Although the Company has established a need for a short-term capacity increment in its Brockton division, the Company failed to establish that it considered a full range of capacity options in reaching its decisions on Meadow Lane and Easton. By its own testimony, the Company recognized that load elimination programs that replace capacity increases could be cost-justified. Nonetheless, the Company failed to consider a load elimination program as an alternative to the capacity increases at Meadow Lane or Easton. Similarly, the Company failed to establish that it evaluated its capacity additions relative to the option of continuing its vaporization contracts with Providence Gas.

Accordingly, the Siting Council finds that Bay State failed to establish that it properly applied its supply planning process in reaching a decision to expand capacity at its Meadow Lane propane facility and Easton LNG facility.[28] The Siting Council therefore finds that the Company failed to establish that the addition of this capacity contributes to a least-cost supply plan.

c. Conservation

Mr. Ellis stated that the Company's efforts to identify, evaluate and implement cost-effective conservation programs are still largely in the developmental stage, and, therefore, the Company does not yet compare conservation programs with other supply options on a regular basis (Exh. BSG-3 (Ellis), pp. 3-4). Mr. Ellis also stated, however, that the Company will proceed with the CCC program, a conservation program it believes to be cost-effective (id.). The Company proposed to invest an additional $1.5 million during the forecast period in this program (Tr. 4, pp. 26-28; Exhs. BSG-3 (Davis), pp. 5-6, HO-SP-33).

In support of its position that the program is cost-effective, the Company presented information showing the energy savings associated with the investment in CCC program program thus far. Mr. Davis indicated that the Company made its decision to invest an additional $1.5 million because that level of funding would not "have a material effect on"

28/ The record in this case includes references to the Company's intention to evaluate a possible capacity expansion at the Marshfield LNG facility. The Siting Council firmly expects that any planning decisions regarding Marshfield will result from proper application of the Company's process.

customers bills, but added that by any of several cost standards, the additional funds would constitute a cost-effective supply option (Tr. 4, pp. 26-28). Although the Company asserted that this program is cost-effective and results in measurable energy savings, the Company did not identify specific energy savings anticipated through the expansion of this program during the forecast period, nor did the Company include the anticipated savings from the CCC program as a resource in its base case supply plan for meeting its firm sendout requirements. Rather, the Company reiterated its assertion that resources made available through the expansion of this program and other conservation programs will be reflected through their impact on the Company's forecast of future requirements (Bay State Brief, p. 40; Tr. 3, p. 70).

The Siting Council recognizes that the implementation of conservation measures in the gas industry is a relatively recent occurrence and that not all companies have completely integrated conservation with traditional supplies in their supply plans. The Siting Council further recognizes that the Company's inclusion of conservation resources in its supply plan is limited by its on-going efforts to identify programs. In this context, the Company's identification and evaluation of its CCC program as a cost-effective supply option is to be commended.

In light of the foregoing, the Siting Council finds that the Company properly applied its supply planning planning process in reaching a decision to expand the CCC program and that expansion of the CCC program contributes to a least-cost plan.

The Company's failure to incorporate anticipated savings from conservation programs in its base case supply plan raises serious questions, however, regarding Bay State's view of conservation options. Here, the Company has invested in the CCC program, a conservation program with significant and verified savings. Nonetheless, the Company's base case supply plan does not reflect the CCC program.

In the 1989 Fitchburg Decision, the Siting Council stated there was no apparent reason for the Fitchburg Gas and Electric Light Company to exclude conservation and load management from its base case resource plan (EFSC 86-11(A), p. 42). Similarly, we find here that Bay State should include in its base case supply plan cost-effective conservation programs.

While the Company argues that conservation program savings can be captured through adjustments in its sendout forecast, this approach reveals a disturbing bias against conservation. In essence, the Company has adopted a "wait and see" approach to conservation. Once the Company can "see" that conservation programs yield results, it can reduce its sendout forecast and adjust future resource plans accordingly. However, while the Company "waits" for conservation programs to prove themselves, it runs the risk of obtaining unnecessary supply resources and subjecting its ratepayers to higher costs.

Conservation measures are fully capable of providing gas companies with cost-effective, reliable resources. Certainly, verified and documented programs such as the CCC program represent the same reliable baseload supply as more traditional resources. As such, these programs warrant the same treatment as any cost-effective traditional resource. A company the size of Bay State should be sophisticated enough to be able to incorporate, without double counting, the impact of previous conservation measures in its forecast and the anticipated savings from planned programs for inclusion in a supply plan. Until such time as Bay State includes cost-effective conservation programs in its base case supply plan, the Company's commitment to conservation as a reliable and cost-effective resource will be suspect. Therefore, the Siting Council ORDERS Bay State in its next filing to: (1) quantify the savings of its existing and planned conservation programs over the forecast period; and (2) fully incorporate these estimates into its base case resource plan and its analyses of adequacy for normal and design conditions.

d. Load Management

The Company asserted that its interruptible sales program, a type of load management, has resulted in substantial benefits to its firm customers (Exh. BSG-3 (Ellis), p. 5). The Company stated that as a result of its interruptible sales, the Company achieved load factors of over 100 percent for its baseload pipeline supplies during both 1987 and 1988 (id.). In addition, as a result of its new marginal sales program, the Company asserts that it was able to reduce the cost of gas to its firm customers by $36,945 during the winter of 1987-88 (id., pp. 6-7). The Siting Council finds that the Company properly applied its supply planning process in reaching a decision to pursue its more traditional load management programs and that these load management efforts contribute to a least-cost plan.

Although the Company appropriately treated interruptible sales, a more traditional load management practice, it did not similarly treat peak-load shedding, a non-traditional option. Peak-load shedding occurs when a firm gas customer discontinues its use of gas during peak periods. The Company did identify the volumes of gas that potentially could be eliminated during peak periods (Exh. BSG-3 (Ellis), p. 11; Tr. 3, pp. 52-56), but presented the position that such a program was not cost-effective at this time (id., Exh. BSG-3 (Ellis), p. 10). The Company stated that in order for a dual fuel customer to discontinue its use of gas during peak periods, Bay State would be required (1) to compensate the customer for the cost of the substitute fuel, and (2) to provide some degree of additional incentive. Further, the Company contended it would incur the costs associated with ensuring that the customers go off-line when requested, including necessary equipment and administrative costs. Mr. Ellis stated, however, that "in the long-run, as additional daily supplemental gas capacity is required and the cost of that capacity is factored into the equation, perhaps this load shedding mechanism will become cost effective" (Exh. BSG-3 (Ellis), p. 20). Mr. Ellis contended that such a program would likely only delay the need for additional capacity by a year, after which it would fail to be cost-effective (Tr. 3, 151-152). Mr. Ellis stated that the Company would evaluate this program prior to each winter to determine its cost-effectiveness relative to other supply options.

The Siting Council recognizes that, as is the case with conservation, the development and incorporation of non-traditional load management programs within the gas industry is a relatively recent occurrence. In addition, the Siting Council understands that some load management programs are not readily evaluated as a supply resource. In this case, however, the Siting Council is concerned that the Company has not fully considered the potential benefits of a peak-load shedding program as a supply resource. The Company has identified the program and quantified the peak-load shedding capability associated with the program, but has not developed appropriate criteria to test the cost-effectiveness of the program. The Company appears to reject the program because there are insufficient energy cost savings. But Mr. Ellis noted that if there are capacity savings associated with the program, it would likely become cost-effective (Tr. 3, pp. 151-152).

The Siting Council notes that the MDPU, in its recent Bay State Company rate case order, found that the Company's cost/benefit test for this peak-load shedding program was not conducted in accordance with the MDPU's definition of cost-effectiveness (D.P.U. 89-81, p. 219 (October 31, 1989)). The Siting Council shares the MDPU's concerns that the Company failed to properly consider capacity costs associated with the program and did not justify its position concerning payments of premiums to customers to convince them to switch to their alternate fuel.

Based on the foregoing, the Siting Council finds that the Company failed to establish that it properly applied its supply planning process in evaluating the cost-effectiveness of peak-load shedding programs. Accordingly, the Siting Council ORDERS the Company to provide in its next filing a detailed cost study consistent with the MDPU's definition of cost-effectiveness, and to include such a program in its supply plan if this study shows load elimination to be cost-effective.

Further, the Siting Council notes that the Company should begin to include supplies made available through implementation of load management programs in its supply plan. Accordingly, the Siting Council ORDERS Bay State in its next filing to: (1) quantify the savings of its existing and planned load management programs over the forecast period; and (2) to incorporate these programs into its base case resource plan and its analyses of adequacy for normal and design conditions.

3. Conclusions on Least Cost Supply

The Siting Council has found that the Company properly applied its supply planning process in reaching decisions regarding the Shell volumes, the NEA volumes, expansion of conservation programs, and certain load management programs. The Siting Council also has found that each of these supply decisions contributes to a least-cost supply mix.

The Siting Council also has found that the Company failed to establish that it properly applied its supply planning process in reaching its decisions regarding the capacity expansion at the Meadow Lane propane and Easton LNG facilities, and the cost-effectiveness of load elimination programs. The Siting Council is therefore unable to find that the Company's decisions regarding the capacity increases at Meadow Lane and Easton and load elimination programs contribute to a least-cost supply plan. Nonetheless, the Siting Council finds that the potential adverse impact of the decisions regarding the capacity increases at Meadow Lane and Easton and load elimination programs is minimal in relation to the cost and other benefits realized by the Company's decisions regarding the Shell volumes, the NEA volumes, and increased investment in conservation measures.

Accordingly, the Siting Council finds that, on balance, the Company's supply decisions contribute to a least-cost supply plan. Accordingly, the Siting Council further finds that the Company's supply plan minimizes cost.

G. Conclusions on the Supply Plan

The Siting Council has found that Bay State has established that: (1) its supply planning process enables it to make least-cost supply decisions; (2) it has adequate resources to meet its firm sendout requirements throughout the forecast period; (3) its supply decisions, on balance, contribute to a least-cost supply plan, and its supply plan minimizes cost; and (4) it has complied with Condition Three of the 1987 Bay State Decision. Accordingly, the Siting Council APPROVES Bay State's supply plan.

In approving the Company's supply plan, the Siting Council notes the strides made by the Company since our last decision. Bay State now acknowledges that conservation and load management are appropriate supply resouces and has taken initial steps to include them in the supply planning process. In addition, Bay State appears to have improved its criteria for judging resource options. Further, the Siting Council recognizes the creative supply options, such as the NEA oil/gas swap, that Bay State has identified and evaluated, and the impressive level of experience Bay State's management brings to supply planning.

Nonetheless, the Company's supply plan retains certain marked infirmities that were identified in the 1987 Bay State Decision. First, the Company has an informal, ill-defined, supply planning process. Given the complexity of gas supply planning and the size and resources of Bay State, it should have a systematic, well-documented methodology for identifying and evaluating supply options. No amount of experience can substitute for such a methodology.

Second, the Company continues to demonstrate a bias against non-traditional supply resources, such as conservation and load management. It fails to compare conservation and load management programs with the other supply options on a equal footing and it does not incorporate planned savings from conservation programs in its base case supply plan.

Throughout this order, the Siting Council has recognized the limited experience which gas companies have acquired thus far with conservation and load management programs and has accepted that the initial efforts to consider these programs may be less than comprehensive. However, the time for initial efforts now has passed, and the Company, in its next forecast and supply plan filing, must demonstrate it has fully integrated conservation and load management into its supply planning process and decisions.

IV. DECISION AND ORDER

The Siting Council hereby APPROVES the sendout forecast and supply plan of Bay State Gas Company as presented in its Second Supplement to its Third Long-Range Forecast.

The Siting Council ORDERS Bay State in its next forecast filing:

(1) to detail the process it has used to establish a design year probability of occurrence criterion, the costs associated with that probability criterion over the forecast period, and the cost of other probability criteria considered over the forecast period. Further, if no other probability criteria were considered, the Company should provide justification and include a sensitivity analysis around the selected criterion to show how different criteria levels result in different levels of cost;

(2) to detail the process it has used to establish a design day probability of occurrence criterion, the costs associated with that probability criterion over the forecast period, and the cost of other probability criteria considered over the forecast period. Further, if no other probability criteria were considered, the Company should provide justification and include a sensitivity analysis around the selected criterion to show how different criteria levels result in different levels of cost;

(3) to develop a design day forecasting methodology which treats each of its divisions separately, or provide justification that the potential increase in reliability of the forecast does not warrant such an effort;

(4) to include: (1) a detailed listing of the all supply options identified by the Company for consideration for the forecast period (whether pursued or not); (2) a detailed description of the criteria the Company either used or will use in evaluating the options; and (3) a thorough explanation of how the Company will ensure that all resource options are considered on an equal footing;

(5) to quantify the savings of its existing and planned conservation programs over the forecast period, and fully incorporate these estimates into its base case resource plan and its analyses of adequacy for normal and design conditions;

(6) to provide in its next filing a detailed cost study evaluating the cost-effectiveness of peak-load shedding programs, consistent with the MDPU's definition of cost-effectiveness, and to include any such programs in its supply plan if this study shows load elimination to be cost-effective;

(7) to quantify the savings of its existing and planned load management programs over the forecast period, and to incorporate these programs into its base case resource plan and its analyses of adequacy for normal and design conditions.

The Siting Council further ORDERS Bay State to file its next forecast on January 1, 1991.

Stephen Klionsky

Stephen Klionsky
Hearing Officer

Dated this 30th day of November, 1989

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of November 30, 1989 by the members and designees present and voting. Voting for approval of the Tentative Decision as amended: David A. Tibbetts (Acting Secretary of Energy Resources); Paul Gromer (for Mary Ann Walsh, Secretary of Consumer Affairs and Business Regulation); Joellen D'Esti (for Alden S. Raine, Secretary of Economic Affairs); Janet McCabe (for John P. DeVillars, Secretary of Environmental Affairs); Dennis LaCroix (Public Gas Member); and Kenneth Astill (Public Engineering Member).

David A. Tibbetts

David A. Tibbetts
Chairperson

Dated this 30th day of November, 1989

TABLE 1

Bay State Gas Company
Split-Year Forecast of
Firm Sendout by Customer Class
(BBtu)

	1988-89		1992-93	
	Normal	Design	Normal	Design
Brockton				
Residential Heating	8,682	9,296	9,911	10,645
Residential General	393	397	330	333
Commercial	4,946	5,006	5,124	5,187
Industrial	1,318	1,327	1,472	1,483
Brockton Total[1]	15,715	16,974	17,262	18,656
Lawrence				
Residential Heating	3,979	4,248	4,487	4,786
Residential General	156	158	101	102
Commercial	1,663	1,680	1,713	1,730
Industrial	956	963	884	891
Springfield				
Residential Heating	6,456	6,898	7,042	7,523
Residential General	507	511	447	451
Commercial	4,457	4,506	4,699	4,751
Industrial	1,274	1,283	1,272	1,280
Springfield and Lawrence Total[1,2]	22,600	24,798	22,801	24,761
COMPANY TOTAL	38,316	41,772	40,062	43,417
Sales for Resale[3]	2,165	2,897	1,105	1,483

Notes:

1. Includes Company-use and unaccounted-for gas.
2. Springfield and Lawrence total sendout combined by Company to account for interdivision supply flexibility.
3. The Company includes firm contract obligations in normal year planning and firm plus optional contract obligations in design year planning.

Sources: Exhs. BSG-1, Tables G-1 through G-5, HO-SP-51

TABLE 2

Bay State Gas Company
Comparison of Resources and Requirements
Design Year - Heating Season (BBtu)

Brockton Division

Requirements	1989-90	1990-91	1991-92	1992-93
Firm Sendout	12289.4	12625.8	12968.7	13236.2
Sales for Resale	883.6	811.1	860.1	549.8
Fuel Reimbursement	57.4	57.4	57.4	57.4
TOTAL	13230.4	13494.3	13886.2	13843.4
Resources				
Granite CD-1	1910.5	1910.5	6289.5[1]	6289.5
AGT F-1	5048.5	5048.5	5048.5	5048.5
F-4	859.2	859.2	859.2	859.2
WS-1	1091.9	1091.9	1091.9	1091.9
AGT Storage Return				
STB	676.9	676.9	676.9	676.9
SS-III	723.6	723.6	723.6	723.6
LNG from storage	833.4	833.4	833.4	833.4
DOMAC + WS-1 Excess	1760.9	1760.0[2]	0.0	0.0
Bellingham	0.0	180.0[2]	120.0	150.0
Propane from storage	0.0	100.0[2]	0.0	0.0
Firm Propane Purchases	120.0	120.0[2]	35.0	35.0
LNG Transfer[3]	205.5	200.0[2]	153.8	122.3
TOTAL	13230.4	13504.0	15831.8	15830.3
Interruptible Sales[4]	0.0	1107.0	888.1	929.4

Notes:

1. This reflects an increase in CD-1 volumes of 29 BBtu per day beginning in November 1991.

2. As discussed in Sections III.D and III.E, as a result of the delay of the new pipeline supplies the Company's indicated that it would adjust its use of these supplies as needed to meet firm sendout requirements.

3. Bay State makes transfers of LNG from Springfield to Brockton; these volumes reflect the Company's initial plans except for the 1990-91 heating season (see note 2 above).

4. These sales reflect the Company's initial supply plans, the Siting Council notes that actual sales will vary as available supplies vary.

Sources: Exhs. BSG-1, Table G-22 D, HO-SF-29

TABLE 3

Bay State Gas Company
Comparison of Resources and Requirements
Design Year - Heating Season (BBtu)

Springfield/Lawrence

Requirements	1989-90	1990-91	1991-92	1992-93
Firm Sendout	15689.8	15981.9	16214.6	16444.2
Sales for Resale	1376.1	1300.1	1356.6	933.6
Fuel Reimbursement	97.2	97.2	97.2	97.2
LNG Transfer[1]	205.5	200.0	153.8	122.3
TOTAL	17368.6	17579.2	17822.2	17597.3
Resources				
Granite CD-1	13664.4	13664.4	13883.4[2]	13883.4
Granite Storage Return				
GSS-1	1622.7	1622.7	1622.7	1622.7
S-1 Firm	1692.9	1692.9	1692.9	1692.9
S-1 Int.	205.2	205.2	205.2	205.2
LNG from storage	929.5	576.7	822.4	743.8
Propane from storage	0.0	0.0	0.0	0.0
Firm Propane Purchases	30.0	20.0	20.0	20.0
TOTAL	18144.7	17781.9	18246.6	18168.0
Interruptible Sales[3]	776.1	1297.9	1111.4	1257.7

Notes:

1. Bay State makes transfers of LNG from Springfield to Brockton; these volumes reflect the Company's initial plans except for the 1990-91 heating season (see Table 2).

2. This reflects an increase in CD-1 volumes of 1,450 MMBtu per day beginning in November 1991.

3. These sales reflect the Company's initial supply plans. The Siting Council notes that actual sales will vary as available supplies vary.

Sources: Exhs. BSG-1, Table G-22 D, HO-SF-29

TABLE 4

Bay State Gas Company
Comparison of Resources and Requirements
Design Day (BBtu)

Brockton

Requirements	1989-90	1990-91	1991-92	1992-93
Total Firm Sendout	161.6	165.8	170.5	172.2
Resources				
Granite CD-1	6.7	6.7	35.7[1]	35.7
AGT F-1	33.4	33.4	33.4	33.4
F-4	5.6	5.6	5.6	5.6
WS-1	18.2	18.2	18.2	18.2
LNG from storage	62.0[2]	62.0	62.0	62.0
Bellingham	0.0	60.0	60.0	60.0
Propane from storage	47.3[2]	47.3	47.3	47.3
TOTAL	173.2	233.2	262.2	262.2

Notes:

1. This reflects an increase in CD-1 volumes of 29 BBtu per day beginning in November 1991.

2. These volumes reflect inclusion of the Company's increases at the Meadow Lane and Easton facilities.

Sources: Exhs. BSG-1, Table G-23, HO-SF-28

TABLE 5

Bay State Gas Company
Comparison of Resources and Requirements
Design Day (BBtu)

Springfield/Lawrence

Requirements	1989-90	1990-91	1991-92	1992-93
Total Firm Sendout	204.5	208.0	211.5	211.6
Resources				
Granite CD-1	96.4	96.4	97.85[1]	97.85
Granite Storage Return S-1 Firm	14.9	14.9	14.9	14.9
LNG from storage	74.7	74.7	74.7	74.7
Propane from storage	70.9	70.9	70.9	70.9
TOTAL	256.9	256.9	258.35	258.35

Notes:

1. This reflects an increase in CD-1 volumes of 1,450 MMBtu per day beginning in November 1991.

Sources: Exhs. BSG-1, Table G-23, HO-SF-28

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 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 services 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 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. (See. 5, Chapter 25, G.L. Ter. Ed., as most recently amended by Chapter 485 of the Acts of 1971).

2197H

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of)
The Berkshire Gas Company for)
Approval of its Forecast of Gas)
Resources and Requirements)

EFSC 89-29 (Phase 1)

FINAL DECISION

Sue Munis Nord
Hearing Officer
February 9, 1990

On the Decision:

William Febiger

APPEARANCES:

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The Energy Facilities Siting Council hereby: (1) APPROVES the sendout forecast and (2) APPROVES, upon the Company's compliance with the conditions set forth herein, the supply plan filed by the Berkshire Gas Company for the five years from 1987-88 through 1991-92.

I. INTRODUCTION

A. Background

The Berkshire Gas Company ("Berkshire" or "Company") distributes and sells natural gas in 19 communities in Berkshire, Franklin and Hampshire Counties.[1] In the split-year 1986-87,[2] the Company had an average of 27,719 firm service customers, consisting of 16,749 residential customers with gas heating; 7,942 residential customers without gas heating; 3,013 commercial customers; and 15 industrial customers (Exh. HO-1, Tab 2, Tables G1, G2, G3A and G3B). Berkshire also sells gas to interruptible customers (id., Table G4A).

Berkshire's forecasts of sendout by customer class for both a normal year and a design year are summarized in Table 1 (id., Tables G1 through G5). The Company projects an increase of total normalized firm sendout from 4,997 million cubic feet ("mmcf") in 1987-88 to 5,148 mmcf in 1991-92, representing an average annual rate of increase of 0.75 percent over the forecast period.

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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"), Berkshire is considered to be a medium-sized gas company.

[2] A split-year runs from November 1 through October 31, and includes a heating season and a non-heating season. The heating season is defined as the period from November 1 through March 31. The non-heating season extends from April 1 through October 31.

Berkshire receives pipeline gas and underground storage return gas[3] from the Tennessee Gas Pipeline Company ("Tennessee") at its Stockbridge, Pittsfield, North Adams and Northampton gate stations. Berkshire also receives, under transportation arrangements with Tennessee, pipeline gas from Boundary Gas Incorporated ("Boundary") and supplemental liquified natural gas ("LNG") supplies from Bay State Gas Company ("Bay State") and Distrigas Corporation ("Distrigas").[4] Finally, Berkshire has auxiliary propane facilities in Stockbridge, Pittsfield, North Adams, Hatfield and Greenfield.

B. Procedural History

On February 1, 1988, Berkshire filed its 1987 Long Range Forecast of Natural Gas Requirements and Resources ("Forecast"). On October 6, 1988, the Company filed an amendment to the Forecast requesting approval to construct pipeline and metering station facilities in order to connect the Tennesee main line in Richmond, Massachusetts, to the Altresco cogeneration plant in Pittsfield (hereinafter referred to as the "Facility Application"). The Facility Application set forth a description of the pipeline route and meter station site, as well as alternate pipeline routes and an alternate meter station site. Subsequently, the Company filed additional information to amend or supplement its Facility Application.

On January 26, 1989, shortly after the Company's Forecast and Facility Application were deemed complete, the Hearing Officer 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).

3/ Berkshire sends gas to underground storage during the non-heating season and the gas is returned for sendout during the heating season.

4/ The supplemental LNG supplies are vaporized by the suppliers at points on Tennessee's system east of Berkshire's territory and "backhauled" to Berkshire; that is, used to displace volumes being transported on Tennessee's system from points west of Berkshire's territory.

A public hearing was held in the City of Pittsfield on February 23, 1989.

Four petitions to intervene and one request to participate as an interested person in the proceeding were received by the Hearing Officer. On March 31, 1989, the Hearing Officer conducted a pre-hearing conference and granted intervenor status to Altresco-Pittsfield, Inc. ("Altresco"), the Town of Richmond ("Richmond"), Zelda Brandon, and Jeffrey and Marion Grant. Interested person status was granted to Donald and Ingrid MacGillis. The Hearing Officer conducted additional pre-hearing conferences on May 10, 1989 and May 31, 1989.

Among the motions made and ruled on during the course of this proceeding were the following.

On May 24, 1989, Richmond filed a motion for an Additional Notice of Public Hearing and Adjudication for Alternate Routes. In its motion, Richmond requested that the Siting Council issue an additional notice of public hearing and adjudication in order to include in the proceeding pipeline routes proposed by Richmond as alternatives to the Company's preferred route. On May 31, 1989, Zelda Brandon filed a motion in support of the Richmond motion. On June 2, 1989, Berkshire and Altresco filed separate responses in opposition to the Richmond motion. On June 5, 1989, Donald and Ingrid MacGillis filed a letter in support of Richmond's motion. On June 7, 1989, Richmond submitted a letter in rebuttal to Altresco's response.

On June 16, 1989, the Hearing Officer issued a Procedural Order denying the motion on the basis that the Siting Council statute does not provide the Siting Council with the authority to propose its own route or to approve a route not contained in a petitioner's application.

The Siting Council conducted twenty days of evidentiary hearings during the proceeding. Berkshire presented five witnesses: Les H. Hotman, Director of Planning for the Company, who testified regarding the Company's update to the Forecast and Supply Plan and involvement in the Altresco project; Donald P. Atwater, Director of Distribution for the Company, who testified regarding the engineering and site selection process for the pipeline; David M. Haines, a consultant with Haines Hydrogeologic Consulting, who testified regarding the impact of the pipeline on public and private water supplies; Terry A. Tattar, Ph.D, a professor of plant pathology with the University of Massachusetts Shade Tree Laboratory, who testified regarding impacts and recommendations for mitigation of impacts of pipeline construction to trees along the pipeline route; and James Philip Scalise, President of Scalise-Knysh Associates, Inc., who testified regarding initial design, route selection process, engineering, permitting,and environmental concerns for the pipeline.

Altresco presented two witnesses: Barry Curtiss-Lusher, President of EnerProbe Consulting, who testified regarding the status of the Altresco project and the rationale of selecting a Berkshire pipeline proposal; and Dr. Robert Ingram, Senior Environmental Scientist with the Daylor Consulting Group, who testified regarding the results of an independent review of the Berkshire site selection process.

Richmond presented six witnesses: Richard L. Boyce, member of Town of Richmond Conservation Commission, who testified regarding the impact of pipeline construction on trees along the primary and alternate routes; K. Jerry Morray, member of Town of Richmond Planning Board, who testifed regarding Richmond's Scenic Roadways and zoning requirements; David W. Morrison, member of Town of Richmond Board of Selectmen, who testified regarding the potential impact of construction blasting and public safety concerns; Thomas L. Sherer, member of Town of Richmond Planning Board, who testified regarding the impact of pipeline construction on drinking water and sewage disposal systems; Holly Stover, member of Town of Richmond Conservation Commission, who testified regarding various impacts of the proposed pipeline routes in the Town of Richmond; and Peter Walsh, who testified regarding his assessment of the qualifications of Sclise-Knysh Associates, Inc.

None of the other intervenors presented witnesses.

The Hearing Officer entered 195 exhibits into the record, largely composed of responses to information and record requests, which included a response to a Staff supplemental information request which was moved into evidence after the close of the hearings. Berkshire entered 87 exhibits into the record. Altresco entered 16 exhibits into the record. Richmond entered 90 exhibits into the record. Zelda Brandon entered one exhibit into the record.

The Initial Briefs of Zelda Brandon and Richmond were filed on August 15 and 16, respectively. On August 18, 1989, Jeffrey and Marion Grant submitted a letter in support of the Richmond Brief. On August 19, 1989, Donald and Ingrid MacGillis submitted a letter in support of the Richmond Brief. On August 28, 1989, Initial Briefs were submitted by Berkshire and Altresco. Intervenors Richmond and Zelda Brandon and Altresco submitted reply briefs on September 5, 1989. Additional reply briefs were filed by Berkshire and Altresco on September 11, 1989.

After briefs were filed, on December 22, 1989, Richmond and Zelda Brandon filed a Joint Motion to Re-Open Hearings for the limited purpose of receiving new information regarding safety issues. On January 19, 1990, the Hearing Officer denied this motion.

On January 11, 1990, Richmond and Zelda Brandon filed a Supplemental Joint Motion to Re-Open Hearings in order to raise an issue relating to the construction of the Altresco cogeneration project in Pittsfield, the project that Berkshire's proposed pipeline was to serve. On January 29, 1990, Richmond filed a Motion for Administrative Notice and Further Hearings in order to raise an issue relating to a revised Natural Heritage Program map regarding the location of an endangered or rare species habitat along the route of Berkshire's proposed pipeline. These motions have not yet been ruled.

This decision of the Siting Council analyzes the Company's Forecast only. The Hearing Officer herein severs the Forecast from the Facility Application. The Forecast is now denominated as EFSC 89-29 (Phase 1) and the Facility Application, which will follow at a later date, will be denominated as EFSC 89-29 (Phase 2).

II. ANALYSIS OF THE SENDOUT FORECAST

A. Standard of Review

The Siting Council is directed by G.L. c. 164, sec. 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. Bay State Gas Company, EFSC 88-13 (1989) ("1989 Bay State Decision"); Fitchburg Gas and Electric Light Company, EFSC 86-11(A) (1989) ("1989 Fitchburg Decision"); Commonwealth Gas Company, 17 DOMSC 71, 77 (1988) ("1988 ComGas Decision"); Bay State Gas Company, 16 DOMSC 283, 288 (1987) ("1987 Bay State Decision"); Berkshire Gas Company, 16 DOMSC 53, 56 (1987) ("1987 Berkshire Decision"); Boston Gas Company, 16 DOMSC 173, 179 (1987) ("1987 Boston Gas Decision").

In its review of a forecast, the Siting Council determines if a projection method is reasonable according to 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. 1989 Fitchburg Decision, EFSC 86-11(A), p. 4; 1988 ComGas Decision, 17 DOMSC at 77-78; 1987 Bay State Gas Decision, 16 DOMSC at 289; 1987 Berkshire Decision, 16 DOMSC at 55-56; 1987 Boston Gas Decision, 16 DOMSC at 179; Holyoke Gas and Electric Light Department, 15 DOMSC 1, 6 (1986) ("1986 Holyoke Decision"); Westfield Gas and Electric Light Department, 15 DOMSC 67, 72 (1986) ("1986 Westfield Decision").

B. Previous Sendout Forecast Reviews

In 1986, the Siting Council ordered Berkshire to comply with our 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"),[5] and that Decision's implementation in Administrative Bulletin 86-1. Berkshire Gas Company, 14 DOMSC 107, 138-139, 141 (1986) ("1986 Berkshire Decision"). The 1986 Gas Generic Order classified Berkshire as a medium-sized company, which would "file much the same sort of forecasts as the large companies...but they would receive a level of scrutiny -- and assistance -- appropriate to their size and circumstances" (14 DOMSC at 104).

In the 1987 Berkshire Decision, the Siting Council rejected Berkshire's sendout forecast, in large part because it failed to comply with the 1986 Gas Generic Order (16 DOMSC at 57-70). In rejecting the sendout forecast, the Siting Council found that, although the Company's normal year methodology, design year methodology, and design day methodology were reviewable, each of these forecast methodologies was inappropriate and unreliable (id., p. 70).

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, secs. 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

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[5] In the 1986 Gas Generic Order, the Siting Council established procedures which render its review of sendout forecasts and supply plans filed annually by each company more effective in carrying out the Siting Council's statutory mandate by promoting appropriate and reliable sendout forecasting and least-cost, least-environmental impact supply planning.

is the basic input upon which a company's planning standards are based. The second element of our review is an analysis of the planning standards themselves -- how the company arrived at its normal year, design year, and design day standards.[6] A company's standards are used as a basis for projecting its sendout forecast which, in turn, is used to ascertain the adequacy and cost of a company's supply plan. The Siting Council reviews a company's planning standards to ensure that they are reviewable, appropriate and reliable.

1. Weather Data

Berkshire based its sendout forecast on degree-day ("DD") data recorded at the Company's weather station in Pittsfield (Tr. 1, p. 13). The Company stated that it has 35 years of monthly DD records and 27 years of daily DD records (Exh. HO-S-5).

To determine its normal year standard of 7503 DD (see Section II.C.1.b, below), its design year standard of 8166 DD (see Section II.C.1.c, below), and its design day standard of 74 DD (see Section II.C.1.d, below), the Company used Pittsfield DD data for the period from November 1967 through October 1987 (Exh. HO-1, Tab 2, Table DD). The Company stated that these data include the records for the most recent historical split-year period at the time of its filing (id.).

The Company stated that it plans to establish a second weather station in Greenfield in the Connecticut River Valley. The Company noted that weather is milder in Greenfield than in Pittsfield and that more accurate weather data is needed to support planning for new peaking and system supplies in the Greenfield market area (id., Tab 2, p. 7; Tr. 1, p. 13). The Company further stated that it has a goal of segmenting future forecasts into separate market areas, which probably would be based on separating out the Connecticut River Valley market area from the remainder of the Company's service territory,

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6/ In this decision, "design day" is used synonymously with "peak day."

which includes Pittsfield and North Adams (Exh. HO-1, Tab 2, p. 7; Tr. 1, pp. 73-75). The Siting Council previously has found that geographically separate market areas often warrant independent sources of weather data (1988 ComGas Decision, 17 DOMSC at 79-86, 102; 1986 Bay State Decision, 14 DOMSC at 5-22), but this issue has not been addressed explicitly in the Siting Council's previous review of Berkshire's forecast. The Siting Council notes that Berkshire's establishment of a second source of weather data allows the Company to use data which is more reflective of its geographically diverse service territory.

The Siting Council also notes, however, that for an extended period of time the Company does not expect to have sufficient data from the Greenfield weather station to segment its forecast (Exh. HO-S-15; Tr. 1, pp. 73-74). During the interim period, while the Company collects initial data at the new weather station, the Company may be able to achieve its goal of a segmented forecast by relying on other sources of Connecticut River Valley weather data. Although the Company stated that it was not aware of any currently available weather records for the Connecticut River Valley area (id., pp. 75-76), the Siting Council notes that other gas utilities serving areas in the lower Connecticut River Valley in Massachusetts have indicated that they use weather data from within their service areas or from nearby Bradley Field in Windsor Locks, Connecticut. 1987 Bay State Decision, 16 DOMSC at 291; 1986 Holyoke Decision, 15 DOMSC at 8; 1986 Westfield Decision, 15 DOMSC at 74-75. Berkshire should seek to obtain weather data from existing Connecticut River Valley sources, which then may be calibrated to Berkshire's Connecticut River Valley service territory by use of the first two or three years of Greenfield weather data.

For the purposes of this review, the Siting Council finds that Berkshire's use of the Pittsfield weather data to forecast sendout requirements for its overall service territory is appropriate and reliable. However, the Siting Council ORDERS Berkshire in its next forecast filing to provide an analysis of the availability of existing Connecticut River

Valley weather data and the potential to use the first two or three years of Greenfield data to calibrate the existing Connecticut River Valley data for use in a segmented forecast.

2. Normal Year Standard

The Company determined its normal year standard of 7503 DD based on an arithmetic average of 20 years of Pittsfield DD data collected from November 1967 through October 1987 (Exh. HO-1, Tab 2, Table DD).

The Siting Council finds that Berkshire's methodology for determining its normal year standard is reviewable and appropriate. Additionally, because the Siting Council found in Section II.C.1, above, that Berkshire's weather data is appropriate and reliable, the Siting Council finds that the Company's normal year standard is reliable.

3. Design Year Standard

The Siting Council Decision in the 1986 Gas Generic Order placed gas companies on notice 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 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 recur, and to the effect of the design standard on the reliability of the company's forecast and the cost of its supply plan (id., pp. 96-97, 104-105). Further, the Siting Council explicitly ordered Berkshire to comply with the 1986 Gas Generic Order in the 1986 Berkshire Decision, 14 DOMSC 107, 138-39, 141.

In the 1987 Berkshire Decision, the Siting Council found that Berkshire had failed to comply with its order in the 1986 Berkshire Decision (16 DOMSC at 65-67). Further, in the 1987 Berkshire Decision, the Siting Council found that there was insufficient evidence to establish that Berkshire's design year standard provided a reliable basis for estimating design year needs (id., pp. 66-67).

a. Description

Berkshire's design year standard of 8166 DD is the coldest year actually experienced by the Company in the last 20 years (Exh. HO-1, Tab 2, Table DD). The selected design weather conditions, which occurred in 1976-77, also represent the coldest year in the 35-year period for which the Company has monthly weather data (Exh. HO-S-6).

In describing the rationale for its design year standard, the Company cited its belief that reliance on actual year data, rather than a statistically based standard, best meets the Siting Council's requirements as set forth in the 1987 Berkshire Decision (Exhs. HO-S-6, HO-S-21). The Company stated that a statistical analysis was not used to estimate the frequency of occurrence of the design year standard due to serious concerns raised by the Siting Council in its previous review of Berkshire's statistically based design year standard (id.). As an indication of the likelihood that design year conditions might occur in any given year, the Company noted that DD levels for three years during the last 20 years (including the design year itself) are within three per cent of the selected design year standard (Exh. HO-S-21; Tr. 1, pp. 58-59).

Berkshire stated that a design year standard should not be so high as to impose unreasonable costs on customers in developing supplies based on such standard (Tr. 1, pp. 77, 81-82). The Company asserted that its design year standard appropriately balances cost and reliability of supply because conditions within the range of the design year standard had occurred recently and very likely could recur (Tr. 1, p. 77). The Company also stated its belief that incremental changes in the design year standard would have little or no impact on the cost of supply (Tr. 3, pp. 21-24). The Company indicated that it had not developed explicit cost analyses to support its selection of a design year standard (id.).

The Company argues that its design year standard is further supported by the results or recommendations of two other studies prepared for the Company (Berkshire Brief, p. 25). First, the Company argues that its chosen design year standard of 8166 DD is very close to the statistically derived standard developed in an analysis by J.F. Pink Associates ("Pink analysis") (id.).[7] The Siting Council notes that the Pink analysis was addressed in the Siting Council's 1987 Berkshire Decision, and thus reflects weather data developed more than two years ago as part of the record in that proceeding (id.). Second, the Company asserts that its design year standard is consistent with results of a dispatch-based analysis conducted by LaCapra Associates ("LaCapra analysis")[8] (id.). The LaCapra analysis includes estimates of average and marginal cost of supply for two sendout levels, representing existing and projected customer requirements under

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7/ Based on the Pink analysis of DD data over a 30-year period, the Company stated that a design year of 8140 DD would have a one-in-20 years probability of occurring (Exh. HO-S-21). The Company calculated the 8140 DD design year level by: (1) determining the statistical measure of one standard deviation from average DDs over a 30-year period of record, (2) multiplying the one standard deviation by a factor of 1.72 to reflect a one-in-20 probability of recurrence, and (3) adding the result to the normal year DD level (id.).

8/ The Company stated that it requested LaCapra Associates to prepare a report as a check on the forecasting and resource planning assumptions in the current forecast filed with the Siting Council (Exh. HO-S-1S). The report included a dispatch-based analysis of (1) the relationship between daily DD and sendout, and (2) existing and projected split-year sendout and cost of supply (average and marginal) for a "typical" normal-year mix of weather conditions (id.). LaCapra Associates also is engaged in developing a framework for Berkshire to use in analyzing conservation and load management as part of a least-cost supply plan (see Section III.E.1, below).

a "typical" normal year mix of weather conditions (Exh. HO-S-1S).[9]

Altresco argues that the Company's design year standard strikes an appropriate balance between cost and reliability, based on evidence that the DD level is within the range that has occurred with sufficient frequency during the historic time period (Altresco Brief, p. 12). Further, Altresco argues that, to the extent there may be concerns that costs of supply are increased by any conservatism in Berkshire's design year standard, such concerns would be offset by Berkshire's unique propane arrangements (id.). Altresco notes that Berkshire purchases its propane supplies from a subsidiary of Berkshire that directly serves retail propane customers, and thus does not pay to maintain inventory volumes (id.).

b. Analysis

The rationale provided by Berkshire for its selection of a design year standard raises several issues.

First, the Company misstates the conclusions of our 1987 Berkshire Decision when it asserts that the Siting Council held in that case that reliance upon actual year data, rather than a statistically derived standard, best meets the Siting Council's requirements. Taken in its full context, the Siting Council's analysis and findings address the inconsistency of the evidence that Berkshire presented in that case regarding its determination of recurrence frequency, rather than the use of statistically based standards in gas utility forecasts per se (1987 Berkshire Decision, 16 DOMSC at 56-70). Indeed, the Company's own witness, Mr. Hotman, acknowledged that he did not interpret the Siting Council's 1987 Berkshire Decision to mean that a company should not use statistical analyses to determine

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[9] The two levels of sendout in the LaCapra analysis are 5213.4 mmcf (1987-88) and 5955.1 mmcf (1991-92) (Exh. HO-S-1S). By comparison, the Company's sendout forecast in 1991-92 is 5548 mmcf for a normal year and 5677 mmcf for a design year, which falls within the range of the two sendout levels in the LaCapra analysis (Exh. HO-1, Tab 2, Table G5).

a proper design year standard (Tr. 1, p. 60).

Second, Berkshire did not provide an explicit cost analysis to support its assertion that its design year standard appropriately balances cost and reliability of supply. Although Altresco notes that the significance of the marginal costs associated with Berkshire's potentially conservative design year standard may be tempered by its propane arrangements, Berkshire did not provide an explicit analysis to measure the significance of those marginal costs. In addition, while the 20 year recurrence frequency may provide some measure of confidence that Berkshire's design year standard does not impose any significant unwarranted supply costs, Berkshire failed to provide any analysis of the tradeoffs between cost and reliability of supply associated with its design year standard. While the Siting Council notes that medium-sized companies, such as Berkshire, are not required to analyze the tradeoffs between reliability and cost associated with a design year standard with the same level of sophistication as that which is expected of the largest gas companies, a medium-sized gas company must establish that it has performed some analysis of these tradeoffs before setting its design year standard.

Third, while the Pink analysis provides some support for the Company's assertion that its design year standard ensures supply reliability for Berkshire's customers, the Siting Council notes that the Pink analysis relies on data developed in conjunction with the previous Siting Council review and that it may no longer reflect current experience (see Section II.C.3.a, above).

Fourth, the Siting Council is unable to conclude that the LaCapra analysis, as presented in this record, addresses the selection of a design year standard. Although relevant to the Company's assumptions about usage factors, which affect the Company's calculation of design year and a design day sendout (see Sections II.C.2 and II.C.3, below), the LaCapra analysis does not address the appropriateness of the Company's design year planning standards. The Siting Council notes that Berkshire indicated it will consider the LaCapra analysis when it develops planning assumptions for its next forecast, but there is no indication that the Company used the information and methodologies in the LaCapra analysis in developing the design year standard in the current forecast (id.).

Although Berkshire provided the Pink and LaCapra analyses as checks on the forecast and stated its intention to consider these methodologies in future filings, the Siting Council ultimately must base its review on the planning standards and related sendout projections that the Company actually filed as its sendout forecast. The Company's planning standards and sendout projections in the current review do not incorporate the methodologies used in the Pink and LaCapra analyses. While the Siting Council recognizes that the Pink and LaCapra analyses may offer Berkshire an opportunity to improve its design year standard, the Company has failed to demonstrate that it specifically plans to use these studies in such a manner. Further, the Company has not demonstrated that it has the ability to incorporate the methodologies in the Pink and LaCapra analyses as an integral part of its forecast on an ongoing basis. The Siting Council cannot simply rely on commissioned studies that have been provided as an independent check on the current filing, in order to determine that a company utilizes acceptable methodologies.

In sum, Berkshire has not fully complied with the 1986 Gas Generic Order (14 DOMSC at 96-97, 104-105) and the related order in the 1986 Berkshire Decision (14 DOMSC 107, 138-39, 141), as both pertain to the selection of a design year standard based on an acceptable methodology for a medium-sized company.

Based on the record, the Siting Council finds that the Company has established that its design year standard is reviewable and reliable, but finds that the Company has failed to establish that the design year standard is appropriate. Our finding that the Company's design year standard is reviewable reflects not only the Company's derivation of its standard, but also the applicable elements in the Pink analysis of recurrence frequency and the LaCapra analysis of average and marginal cost. Our finding that the design year standard is minimally reliable is based largely on the supporting data in the Pink analysis and the LaCapra analysis. Our finding that the design year standard is not appropriate is based on the Company's failure to adequately consider the tradeoffs between cost and reliability, and its failure to develop a statistically based standard as part of its forecast.

In making these findings, the Siting Council notes that medium-sized companies, such as Berkshire, have sufficient resources to develop a statistically derived design year standard. Accordingly, the Siting Council ORDERS Berkshire, in its next forecast filing, to submit a statistically derived design year standard.

The Siting Council also ORDERS Berkshire, in its next forecast filing, to submit an analysis of the cost implications of at least two differing levels of reliability of supply as part of its selection of a design year standard.

4. Design Day Standard

The Siting Council's decision in the 1986 Gas Generic Order (14 DOMSC at 97), regarding the development of design criteria applies to both design year and design day standards. 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 1987 Berkshire Decision, the Siting Council found that there was insufficient evidence to establish that Berkshire's design day standard provided a reliable basis for estimating design day needs (16 DOMSC at 68). Further, the Siting Council found, in the 1987 Berkshire Decision, that Berkshire had failed to comply with an earlier Siting Council order requiring Berkshire to provide a rationale for the selection of its design day criteria (id.).

a. Description

Berkshire's design day standard of 74 DD is the coldest day actually experienced by the Company in the last 20 years

(Exh. HO-1, Tab 2, Table DD). The selected design day weather conditions also represent the coldest day in the 27-year period for which the Company has daily weather data (Exh. HO-S-6).

In describing the rationale for its design day standard, the Company once again cited its belief that reliance on actual data, rather than on a statistically based standard, was required in the 1987 Berkshire Decision (Exhs. HO-S-6, HO-S-21). See Section II.C.3.a, above. As an indication of the likelihood of occurrence, the Company noted that a 74 DD level had occurred twice in the last 20 years and three times during the last 27 years (Exh. HO-S-5).

Berkshire stated that a design day standard should not be so high as to impose unreasonable costs on customers in developing supplies based on such standard (Tr. 1, pp. 77, 81-82). See Section II.C.3.a, above. The Company stated its belief that the design day standard is analytically important when considering marginal costs and tradeoffs between cost and supply reliability (Tr. 3, pp. 21-24). However, the Company indicated that it had not developed explicit cost analyses to support its selection of a design day standard (Tr. 3, pp. 22-25).

In further support of its design day standard, the Company again pointed to the Pink and LaCapra analyses and argued that the appropriateness of its design day standard of 74 DD is supported by the results or recommendations of these studies (Berkshire Brief, pp. 27-28). First, the Company argues that its chosen design day standard of 74 DD is confirmed by the statistically derived standard developed in the Pink analysis (id.).[10] Second, the Company asserted that its design day standard is consistent with the design day level incorporated as part of the daily dispatch model included in the LaCapra analysis (id.). See Section II.c.1.a, above. The

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[10] The 74 DD level was identified in the Pink analysis as having a one-in-20 years probability of occurring based on Berkshire's then-available weather records (1987 Berkshire Decision, 16 DOMSC at 68; Exh. HO-S-21).

mix of daily weather conditions in the LaCapra analysis includes a design day of 74 DD (Exh. HO-S-1S, p. 4). As with the design year standard, Altresco argues that the Company's design day standard strikes an appropriate balance between cost and reliability, based on evidence that the DD level is within the range that has occurred with sufficient frequency during the historic time period (Altresco Brief, p. 12). See Section II.C.3.a, above.

b. Analysis

The rationale provided by Berkshire for its selection of a design day standard raises issues identical to those raised by Berkshire's selection of a design year standard, and prompts the same concerns -- failure to consider tradeoffs between cost and reliability, use of commissioned studies as forecast checks rather than as bases for developing a standard, and failure to develop a statistically derived standard -- addressed in our earlier analysis. See Section II.C.3.b, above.

Therefore, Berkshire has not fully complied with the 1986 Gas Generic Order (14 DOMSC at 96-97, 104-105) and the related order in the 1986 Berkshire Decision (14 DOMSC 107, 138-39, 141), as both pertain to the selection of a design day standard based on an acceptable methodology for a medium-sized company.

Based on the record, the Siting Council finds that the Company has established that its design day standard is reviewable and reliable, but finds that the Company has failed to establish that the design year standard is appropriate. Our finding that the Company's design day standard is reviewable reflects not only the Company's derivation of its standard, but also the supporting data in the Pink analysis of recurrence frequency and the LaCapra analysis of average and marginal cost. Our finding that the design year standard is minimally reliable is based largely on the supporting data in the Pink analysis and the LaCapra analysis. Our finding that the design year standard is not appropriate is based on the Company's failure to adequately consider the tradeoffs between cost and reliability, and its failure to develop a statistically based standard as part of its forecast.

In making these findings, the Siting Council notes that medium-sized companies, such as Berkshire, have sufficient resources to develop a statistically derived design day standard. Accordingly, the Siting Council ORDERS Berkshire, in its next forecast filing, to submit a statistically derived design day standard.

The Siting Council also ORDERS Berkshire, in its next forecast filing, to submit an analysis of the cost implications of at least two differing levels of reliability of supply as part of its selection of a design day standard.

5. Conclusions on Planning Standards

In previous sections of this Order, the Siting Council has found that: (1) the Company has a reliable and appropriate weather database for use in the development of its planning standards; (2) the Company has a reviewable, appropriate, and reliable normal year standard; and (3) the Company's design year and design day standards are reviewable and minimally reliable, but not appropriate. In making these findings, the Siting Council noted its concerns with certain elements of the Company's planning standards and ordered the Company to supply certain additional information and perform certain additional analyses in its next filing.

Accordingly, for the purposes of this proceeding, the Siting Council finds that the Company's planning standards are reviewable and reliable. However, the Siting Council finds that the Company failed to establish that its planning standards are appropriate.

D. Forecast Methodologies

1. Normal Year and Design Year

In the 1987 Berkshire Decision, the Siting Council rejected the Company's annual sendout forecast methodology. In that decision, the Siting Council found that the Company's normal year and design year forecast methodologies were reviewable, but that neither methodology was appropriate nor reliable (16 DOMSC at 64, 67). Specifically, the Siting Council found that the Company failed to establish that: (1) its customer growth projections were based on reliable data; (2) its assumptions regarding the effects of conservation were appropriate; and (3) the Company's reliance upon normal year use factors in projecting design year sendout requirements provided a reliable basis for estimating design year needs (id., pp. 62-67). The Company asserts that each of these concerns is addressed in its sendout forecast in this proceeding (Berkshire Brief, p. 30).

a. Description

Berkshire forecasts annual sendout under normal and design conditions for each customer class[11] by: (1) determining monthly usage factors for the most recent historical year; (2) projecting monthly usage factors for each forecast year based on annual adjustments for non-programmatic conservation[12]; and (3) multiplying the projected number of customers by projected monthly usage factors for each forecast year and the monthly DD levels for a normal and design year (Exh. HO-1, Tab 2, Tables DD and "Forecast Usage Factors,

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[11] Berkshire divides its customers, for purposes of forecasting sendout, into the following classes: residential heating; residential non-heating; commercial heating; commercial non-heating; industrial; and, interruptible (Exh. HO-1, Tab 2, Tables G1, G2, G3-A, G3-B, and G4-A, "Forecast Usage Factors, 1987-1992").

[12] Conservation that does not result from programs instituted by the Company, but rather that results from other influences such as changes in price or regulations for efficiency standards in new appliances.

1987-92"; Exh. HO-S-11). This calculation provides normal and design year sendout projections on a monthly basis for the five forecast years. Finally, the Company aggregates the monthly sendout projections to derive split-year sendout forecasts for five forecast years on a normal-year and a design-year basis (Exh. HO-1, Tab 2, Tables G1, G2, G3, and G4). The manner in which the Company developed each of the factors used in its normal year and design year forecast methodology is described below.

i. Customer Numbers

The Company developed projections of customer numbers based on: (1) compilations of market area data and growth expectations developed by Berkshire's sales representatives; (2) available demographic data, trends and projections for towns and regions served by Berkshire; (3) estimates of market saturation by town prepared by Berkshire; and (4) trends in price competitiveness and availability of the Company's product (Exhs. HO-1, Tab 2, pp. 13-17, 39; Exhs. HO-S-1, HO-S-19, HO-S-19S, HO-S-20, HO-RR-6; Exh. B-1, p. 5; Tr. 1, pp. 44-54, 115-117). The Company stated that the market area compilations and growth expectations developed by Berkshire's sales representatives were the principal source and starting point for the customer forecast, while the saturation analysis and available demographic information from secondary sources served more as a check on the forecast (Tr. 1, pp. 117-127). The Company stated that, since the previous Siting Council decision, it had instituted cyclical reporting procedures in its marketing department to improve documentation of customer growth projections (Exh. B-1, p. 5; Exh. HO-S-20; Tr. 1, pp. 44-54).

The Company provided the first iteration of sales forecast reports, prepared by sales representatives in 1987, as part of its evidence of its new cyclical reporting procedures (Exh. HO-S-20). The Company's sales forecast reports included quantitative service and sendout projections for the first upcoming year, and included narrative assessments for the remainder of the five-year forecast period (id.).

ii. Usage Factors

In a change from previous forecasts, the Company determined "disaggregated" monthly usage factors for temperature-sensitive use and non-heating customer use in the most recent historical year (Exh. HO-1, Tab 2, p. 37). The Company calculated its disaggregrated monthly usage factors for each temperature-sensitive customer class by subtracting base use[13] from total sales and then dividing by the number of customers in that category for that month (id.). This provided use per customer, which was then divided by the actual degree days experienced in that month, to determine the monthly use per degree day factor (id., Tables DD, G1, G2, G3, G4, and "Forecast Usage Factors"; Exh. HO-S-11).

The record indicates that the Company bases its disaggregation solely on experience in the most recent historical year (Tr. 1, p. 101). However, the Company acknowledged that such an approach is subject to the effect of any monthly anomalies in usage per DD or other sendout factors that may have occurred in the most recent year (id., pp. 101-104). The Company defended its use of data from a single historical year for disaggregation purposes by asserting that earlier years would be rendered inapplicable by conservation trends (id., p. 102). The Company also stated that it "looks at" data from previous years to detect anomalies that may have occurred in the previous twelve months (id., p. 103).

The record indicates that although the Company's calculation of sendout now incorporates disaggregated monthly usage factors, the forecast continues to reflect a linear relationship between changes in DD levels and changes in

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13/ To determine base use per heating customer for five historical years, the Company divided July and August sendout by the average number of customers for September through June (HO-S-7). To determine base use per non-heating customer, the Company divided actual sales by actual customers for each month (HO-S-7; Exh. HO-1, Tab 2, Tables G1, G2).

sendout for affected months (Exh. HO-1, p. 6, Tables G1, G2, G3, G4, and "Forecast Usage Factors, 1987-92"; Exh. HO-S-11). Thus, it is not clear that the new methodology directly reflects any expectation that usage factors could be higher when weather is colder than normal. The Company acknowledged that higher usage factors occur in colder months, and noted that usage factors also are somewhat higher in late winter months as compared to early winter months (Tr. 1, pp. 87-89, 92-93). However, the Company stated that any differences in usage factors attributable to colder-than-normal weather in a design year would not be significant when considered in the context of an entire heating season (id., pp. 93-95).

In further support of its position that constant usage factors by month are applicable to both normal year and design year conditions, the Company presented comparisons of DD's by month and by day for its normal year (20-year average) and design year (1976-77) (Exh. HO-RR-4). With respect to daily usage patterns in its system, the Company also provided a regression analysis prepared by LaCapra Associates of the relationship between DD's and usage for a "typical" mix of daily DD experience consistent in aggregate with a normal year (Exh. HO-S-1S, p. 4, Appendices B and C).

iii. Degree Days

The Company uses a standard of 7503 DD for a normal year and 8166 DD for a design year (see Sections II.C.1.b and II.C.1.c, above).

iv. Conservation Adjustment

The Company stated that its forecast reflects price-induced conservation, based on computation of annual conservation adjustments by customer class (Exh. HO-S-16). The Company stated that it conducted a survey of single family heating customer usage, by month, compiled for two 12-month periods ending June 30, 1986 and June 30, 1987, to help document its conservation assumptions (Exh. HO-1, Tab 2, pp. 36-37).

The Company stated that it adjusted its sendout forecast based on identified conservation factors for each customer class -- that is, annual coefficients used to reduce customer usage factors in successive forecast years (Exh. HO-S-16). The Company stated that it assumed conservation would reduce usage factors at a constant rate, by class, over the forecast period, based on its expectation that gas prices would remain competitive with other energy sources (id.).

b. Analysis

Berkshire's normal year and design year forecast methodologies raise several issues.

First, although the Company has developed procedures for improved documentation of trends in customer numbers through cyclical sales representatives' reports, the Company did not demonstrate that those procedures are being implemented. The Company provided copies of sales representatives' reports, but it was unable to demonstrate that these reports are submitted regularly, or even that a second iteration of the sales representatives' reports had taken place (Tr. 1, pp. 44-54). Further, the Company's sales representative reports incorporate quantitative projections for only the first upcoming year, and rely on qualitative assessments for the remaining four years of the forecast period. In light of the serious concerns raised in the Siting Council's last decision regarding the Company's documentation of customer growth projections (1987 Berkshire Decision, 16 DOMSC at 62-63), the slight progress made by the Company in improving its documentation of customer growth projections is clearly inadequate. In the future, Berkshire should provide submit summaries of sales representatives' compilations to demonstrate that the Company actually has implemented a cyclical documentation process, and that the Company documents its customer growth expectations for a full five-year forecast period; or, in the alternative, to adopt another appropriate, reliable manner for forecasting customer numbers.

Second, the Company's disaggregated monthly usage factors are based on only the most recent historical year. The credibility of the Company's disaggregation approach would be enhanced if a number of historical years were explicitly incorporated into the development of monthly usage factors as a basis for sendout projections. Assuming reasonable efforts to document conservation trends, accurate adjustments for such trends should be possible.

Finally, the Company's normal year and design year sendout forecasts, despite the use of disaggregated monthly usage factors, continue to reflect a linear relationship between changes in DD levels and changes in sendout (Exh. HO-1, Tab 2, p. 6, and "Forecast Usage Factors, 1987-1992"). With respect to the monthly DD comparison, the Company's analysis provided little support for its position concerning constant usage factors. First, the analysis did not confirm the Company's assertion that the monthly "shapes" of DD experience in a normal year and a design year are comparable (Tr. 1, pp. 94-96). Rather, a disproportionate share of the additional DDs in a design year -- 427 DD out of a split-year total of 663 DD -- occurred in the two relatively cold months of December and January (Exh. HO-RR-4). Secondly, regardless of whether the extra DDs are proportionately distributed by month or skewed to either colder or warmer months, the analysis does not address whether the additional DD's involve higher usage factors than the normal year average for respective months.

Unlike the analysis of monthly DD patterns, the analysis of daily patterns of DD's and usage, particularly the regression analysis results, did provide support for the Company's position. The regression analysis confirmed that there is "distress heating" -- that is, higher usage factors in extremely cold weather -- but only when the daily conditions are colder than 65 DD (Exh. HO-S-1S, Appendix B). The Company's design year includes only two days above the 65 DD threshold (both were 67 DD days), which results in an annual total of only 4 DD above the distress heating threshold (Exh. HO-RR-4).

Despite the support for the Company's design year forecast provided by the LaCapra regression analysis, however, there is a remaining concern as to the reliability of the forecast. By representing design year usage patterns based on a single historical year -- the selected design year 1976-77 -- the Company leaves open the possibility that its analysis reflects anomalies in that year with respect to the occurrence of days that are colder than 65 DD. The credibility of the Company's analysis would be considerably strengthened if the analysis were conducted for a number of historical years at or near design levels, rather than just one year.

In sum, the Company has improved the documentation of its normal year and design year forecast methodology in the areas of (a) trends in customer numbers and large-customer sendout and (b) conservation adjustments. In addition, the Company has enhanced its forecast methodology through monthly disaggregation of both base and temperature-sensitive usage trends, and provided new evidence regarding usage per DD that supports its assumption that such usage is not significantly higher in the currently selected design year than a normal year. However, the credibility of the forecast would be improved by further documentation and use of data from more than one historical year, where necessary, to avoid reflecting possible anomalies.

The Siting Council finds that Berkshire's normal year and design year forecast methodology is reviewable, reliable and appropriate. The Siting Council ORDERS the Company, in its next and future filings, to: (a) provide summaries of sales representatives' reports including quantified trends and expectations in customer numbers over five-year forecast periods, as compiled for at least the two most recent internal reporting cycles; or, in the alternative, to adopt another appropriate, reliable manner for forecasting customer numbers; (b) provide documentation of non-programatic conservation trends for all respective customer classes; (c) provide documentation in support of all assumptions regarding the relative usage factors in a normal year and a design year, based on experience in three or more colder-than-normal (design or near-design) historical years, and (d) develop disaggregated monthly usage factors for purposes of projecting sendout based on monthly usage patterns in at least the two most recent historical years.

2. Design Day

a. Description

The Company projected that peak day requirements would increase over the forecast period, based on "controlled addition" of heat sensitive and non-heating load (Exh. HO-1, Tab 2, Table G5).

The Company also provided the LaCapra analysis as an independent check on the sendout forecast. The LaCapra analysis provides a separate projection of design day sendout and addresses the relationship between DD's and usage for a "typical" mix of daily DD experience consistent in aggregate with a normal year (Exh. HO-S-1S, p. 4, Appendices B and C). Both the Company and Altresco assert that the independent estimate of 1991-92 design day sendout in the LaCapra analysis is within 0.2 percent of the Company's own projection for the same year (Company Brief, p. 28; Altresco Brief, p. 16). The Company argues that the LaCapra analysis represents a confirmation that Berkshire used a reasonable statistical approach to develop its design day forecast (Company Brief, p. 28). Altresco argues that the LaCapra analysis verifies the accuracy of the Company's projections (Altresco Brief, p. 15).

b. Analysis

While the Company's design day methodology has benefitted from the slight improvement in the documentation of customer growth projections, there has not been similar progress in the Company's documentation of conservation and analysis of usage factors.

In its previous review, the Siting Council raised concerns regarding the inadequate basis for conservation adjustments to the design day forecast (1987 Berkshire Decision, 16 DOMSC at 69-70). Yet, despite some improved documentation of conservation adjustments for the normal year and design year forecasts (see Section II.C.2.b, above), the Company failed to provide documentation of conservation adjustments for its design day forecast.

In its previous review, the Siting Council also raised concerns with the Company's employment of average use factors, rather than heating and base use factors, to project design day sendout (id., p. 69). Yet, despite incorporation of disaggregated monthly usage factors into the Company's normal year and design year forecasts, the record fails to demonstrate that the Company changed its design day methodology to address the Siting Council's concerns regarding use factors.

Finally, in its previous decision, the Siting Council noted improvements in the Company's documentation of its design day methodology (id., pp. 68-69). These improvements in documentation were not carried over to the Company's current filing, in which the Company failed to provide narrative descriptions of its design day methodology.

Although Berkshire provided the LaCapra analysis as a check on the forecast and stated its intention to consider this methodology in future filings, the Siting Council ultimately must base its review on what the Company actually filed as its sendout forecast. A forecast "check" simply is not a substitute for a reviewable, documented design day forecast methodology. Based on the foregoing, the Siting Council finds that Berkshire's design day forecast methodology is not reviewable. The Siting Council ORDERS the Company, in its next and future filings, to provide documentation of its design day forecast methodology commensurate with that which is to be filed with its normal year and design year forecast methodologies.

The LaCapra analysis utilized a daily dispatch approach, based on a typical normal year mix of DD levels and a regression relationship between daily DD level and daily sendout (Exh. HO-S-S1). Thus, it reflects a distinctly different methodology from that used by the Company's forecast and is indeed a useful check on the accuracy of the Company's current forecast. Based on the foregoing, the Siting Council finds that Berkshire's design day forecast methodology is minimally reliable.

Because the Company failed to provide sufficient documentation of its design day forecast methodolgy to review the appropriateness of that methodology, the Siting Council finds that Berkshire has failed to establish that its design day forecast methodology is appropriate.

3. Conclusions on Forecast Methodologies

The Siting Council has found above that the Company's normal year and design year forecast methodology is reviewable, reliable, and appropriate. The Siting Council has found that the Company's design day forecast methodology is minimally reliable, but neither reviewable nor appropriate. In making these findings, the Siting Council noted its concerns with certain elements of the Company's forecast methodologies and ordered the Company to supply certain additional information and perform certain additional analyses in its next filing.

For purposes of this proceeding, the Siting Council finds that the Company's forecast methodologies are reviewable, reliable, and appropriate.

E. Conclusions on Sendout Forecast

The Siting Council has found that: (1) Berkshire's use of available Pittsfield weather data to forecast sendout requirements is reliable and appropriate; (2) Berkshire's selection of its normal year standard is reviewable, reliable and appropriate; (3) Berkshire's selection of its design year and design day standards are reviewable and minimally reliable; (4) Berkshire's normal year and design year forecast methodology is reviewable, reliable and appropriate; and (5) Berkshire's design day forecast methodology is reliable.

However, the Siting Council has found that Berkshire failed to establish that its selection of a design year standard and a design day standard is appropriate, and failed to establish that its design day forecast methodology is reviewable and appropriate.

Although the Company's forecast still shows some deficiencies, the Siting Council's findings with respect to the sendout forecast show a significant improvement since the previous Berkshire review. In the current review, the Siting Council has found that the Company used assumptions, standards and methodologies which are at least minimally reliable, and that the Company used a normal and design year methodology that is appropriate. In addition, the supporting analyses provide a measure of confidence that suitable analytical techniques can be integrated into the Company's overall forecast approach, as necessary to meet the Siting Council's overall appropriateness standard.

Accordingly, the Siting Council APPROVES Berkshire's forecast of sendout requirements.

III. ANALYSIS OF THE SUPPLY PLAN

A. Standard of Review

The Siting Council is charged with ensuring "a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost." G.L. c. 164, sec. 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.[14] 1989 Bay State Decision, EFSC 88-13, p. 35; 1989 Fitchburg Decision, EFSC 86-11(A), p. 27; 1988 ComGas Decision, 17 DOMSC at 108; 1987 Bay State Decision, 16 DOMSC at 308; 1987 Berkshire Decision, 16 DOMSC at 71; 1987 Boston Gas Decision, 16 DOMSC at 213; Fall River Gas Company, 15 DOMSC 97, 111 (1986) ("1986 Fall River Decision"); 1986 Fitchburg Decision, 15 DOMSC at 54-55; Holyoke Gas and Electric Light Department, 15 DOMSC 1, 27 (1986); Westfield Gas and Electric Light Department, 15 DOMSC 67, 72-73 (1986); Berkshire Gas Company, 14 DOMSC 107, 128 (1986) ("1986 Berkshire Decision").

In its review of a gas company's supply plan, the Siting Council first reviews a company's overall supply planning process. An appropriate supply planning process is essential to the development of an adequate, least-cost, and low environmental impact resource plan. Pursuant to this standard, a gas company must establish that its supply planning process enables it: (1) to identify and evaluate a full range of supply options; and (2) to compare all options -- including conservation and load management ("C&LM") -- on an equal footing. 1989 Bay State Decision, EFSC 88-13, p. 35; 1989 Fitchburg Decision, EFSC 86-11(A), pp. 51-52; 1988 ComGas Decision, 17 DOMSC at 138-139; 1987 Bay State Decision, 16 DOMSC at 323; 1987 Berkshire Decision, 16 DOMSC at 85; 1987

14/ The Siting Council's enabling statute also directs it to balance cost considerations with environmental impact in ensuring that the Commonwealth has a necessary supply of energy. See Section III.C.4, below.

Boston Gas Decision, 16 DOMSC at 252; 1986 Fall River Decision, 15 DOMSC at 115.[15]

The Siting Council next reviews a gas company's five-year supply plan to determine whether that plan is adequate to meet projected normal year, design year, peak day, and cold-snap firm sendout requirements.[16] In order to establish adequacy, a gas company must demonstrate that it has an identified set of resources which meet its projected sendout 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. 1989 Bay State Decision, EFSC 88-13, p. 36; 1988 ComGas Decision, 17 DOMSC at 108; 1987 Bay State Decision, 16 DOMSC at 308; 1987 Berkshire Decision, 16 DOMSC at 71; 1987 Boston Gas Decision, 16 DOMSC at 213.

Finally, the Siting Council reviews whether a gas company's five-year supply plan minimizes cost. A least-cost supply plan is one that minimizes costs subject to trade-offs with adequacy and environmental impact. 1989 Bay State Decision, EFSC 88-13, p. 36; 1988 ComGas Decision, 17 DOMSC at

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15/ In 1986, G.L. c. 164, sec. 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 ComGas Decision, 17 DOMSC at 71, 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 meet projected sendout requirements (pp. 123-126).

16/ 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: 1989 Bay State Decision, EFSC 88-13, p. 36; 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.

109; 1987 Bay State Decision, 16 DOMSC at 309; 1987 Berkshire Decision, 16 DOMSC at 72; 1987 Boston Gas Decision, 16 DOMSC at 214; see New England Electric System, 18 DOMSC 295, 337 (1989) ("1989 NEES 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. Previous Supply Plan Review

In the 1987 Berkshire Decision, the Siting Council rejected Berkshire's supply plan (16 DOMSC at 65). In that decision, the Siting Council found that Berkshire failed to establish that its planned supply additions represented least-cost additions (id.). Further, the Siting Council found that the Company failed to comply with a condition in the Siting Council's previous order that required the Company to base supply additions on cost studies (id., pp. 85-86). Finally, the Siting Council found that Berkshire failed to establish that it makes supply planning decisions pursuant to a process that enables the Company to evaluate a full range of resource options, including conservation and load management, and to distinguish among them on the basis of cost (id.).

In the 1987 Berkshire Decision, the Siting Council also ordered Berkshire to include an updated cold snap analysis in its next filing (16 DOMSC at 87).

Berkshire's compliance with the order in the Siting Council's previous decision and its response to the concerns noted above are discussed in Sections III.C.2, III.E.3, and III.F, below.

C. 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. 1989 Bay State Decision, EFSC 88-13, p. 38; 1989 Fitchburg Decision, 86-11(A), pp. 54-55; 1989 NEES Decision, 18 DOMSC at 336-338, 348-370; Boston Edison Company, 18 DOMSC 201, 224-226, 250-281 (1989) ("1989 Boston Edison Decision"); Eastern Utilities Associates, 18 DOMSC 73, 100-103, 11-131 (1988) ("1988 EUA Decision"); 1987 Boston Gas Decision, 16 DOMSC at 71-72. 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. 1989 Bay State Decision, EFSC 88-13, p. 38; 1987 Bay State Decision, 16 DOMSC at 332. For the Siting Council to determine that the supply planning process is appropriate, the process must be fully documented. 1989 Bay State Decision, EFSC 88-13, p. 38; 1987 Boston Gas Decision, 16 DOMSC at 247, 249; 1987 Bay State Decision, 16 DOMSC at 332; 1987 Berkshire Gas Decision, 16 DOMSC at 84.

Our review of a gas company's supply planning process has focussed primarily on whether (1) the process allows companies to adequately consider conservation and load management options, and (2) the process treats all resource options -- including C&LM options -- on an equal footing. 1989 Bay State Decision, EFSC 88-13, p. 38; 1989 Fitchburg Decision, EFSC 86-11(A), pp. 51-52; 1988 ComGas Decision, 17 DOMSC at 138-139; 1987 Berkshire Decision, 16 DOMSC at 85; 1987 Boston Gas Decision, 16 DOMSC at 252; 1986 Fall River Decision, 15 DOMSC at 115.

In the 1989 Fitchburg Decision, the Siting Council clarified its standard of review, noting that our review of a gas company's process, like our review of an electric company's process, must include an analysis of the company's documented process for identifying and evaluating resource options (EFSC 86-11(A), pp. 54-55). Only through a comprehensive analysis of a company's process for identifying and evaluating resource options can the Siting Council determine specifically whether the process allows for adequate consideration of C&LM and treats all options on an equal footing, and moreover, whether the process as a whole enables the company to achieve an adequate, least-cost, and low environmental impact supply plan.

Now, in reviewing a gas company's process for identifying and evaluating resources, the Siting Council determines whether the company: (1) has a process for compiling a comprehensive array of resource options -- including pipeline, supplemental supply, conservation, load management, and other resources; (2) has established appropriate criteria for screening and comparing resources within a particular supply category; and (3) has a mechanism in place for comparing all resources on an equal footing, i.e., across resource categories.[17] 1989 Bay State Decision, EFSC 88-13, p. 38.

The Siting Council recognizes that fewer resource options may exist for gas companies than for electric companies and consequently that the resource identification and evaluation process may be considerably less complex for gas companies than electric companies. However, the Siting Council concludes that the general framework for reviewing the supply planning process specified above is applicable to gas companies. We also recognize that each gas company will have different supply planning options and needs and that each supply planning process will be different.

While the Siting Council acknowledges that the organization of our review in this case, as in the 1989 Bay State Decision (EFSC 88-13 (1989)), differs somewhat from that of other gas company cases, this reorganization does not establish new regulatory standards or place additional burdens on gas companies. Rather, our intent is to better track the manner in which, we believe, gas company resource decisions are actually made, and to underscore our emphasis on the importance of the planning process as the most critical factor in the implementation of a least-cost plan.

17/ The Siting Council's review of whether the application of the Company's planning process has resulted in a least-cost plan is addressed in Section III.F, below.

2. Identification and Evaluation of Resource Options[18]

The Company stated that its goal is to develop a supply plan that is beneficial in both the long-run and the short-run under conditions of surplus and shortage, balancing flexibility and reliability (id., p. 18). The Company stated that its supply planning process strives to achieve diversification of supply, maintenance of an operationally sound distribution system, and timely expansion of interstate transmission systems to improve current service and meet future demand (id.). Toward this end, the Company stated that it continually monitors and evaluates its existing supplies, as well as alternative supply options (Exh. HO-1, Tab 2, pp. 18, 23).

a. Existing Supplies

The Company stated that it evaluates its existing supplies based on the following considerations: (1) the price level of gas in relation to other fuels; (2) the Company's projections of requirements; (3) the Company's experience with suppliers, in terms of cost responsiveness and reliability;[19] (4) contractual and regulatory requirements, especially with regard to rate structure issues; (5) historical industry fluctuations, with particular focus on balancing cost and

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[18] As indicated in the standard of review, above, the Siting Council in this section reviews only the Company's general supply planning process to determine if the Company's process allows it to make appropriate decisions to achieve an adequate and least-cost supply. In its review of the adequacy and cost of the Company's actual five year supply plan, the Siting Council reviews the Company's application of its supply planning process in making specific decisions. See Sections III.E and III.F, below.

[19] With regard to cost, the Company provided its Supply-Price Comparison Table, and stated that "[a]n analysis of the Company's supply mix in achieving 'Least Cost'" could be derived by examining the table (Exh. HO-1, Tab 2, p. 24). However, the Company's application of the cost table in its supply planning process appears to be limited to qualitative assessments of the cost advantages and disadvantages of the respective supply resources.

reliability considerations; and (6) the quantity and quality of available resource options (id., pp. 18-24).

As a result of its reevaluation of existing supply sources, the Company identified an existing supply contract, its five-year contract with Bay State Gas Company for LNG, which the Company plans to renegotiate in light of changed circumstances (Exh. HO-1, Tab 2, Table G22). The Company stated that due to its settlement of all outstanding issues with Distrigas, the Company now has access to another, cheaper source of LNG which was not available at the time the Bay State LNG contract was negotiated (id., Tables G22N and G22D; Exh. HO-R-5). Accordingly, the Company intends to renegotiate its Bay State contract to reduce its minimum take requirements (id.; Tr.2, pp. 71, 112).

In its past decisions, the Siting Council has not focussed on existing supply sources. However, the Siting Council recognizes that, to the extent existing supply contracts can be renegotiated, periodic reevaluation of existing sources of supply is significant in enabling a company to make least-cost supply planning decisions.

b. Additional Supplies

In addition to its ongoing evaluation of existing supplies, the Company must identify and evaluate new sources of supply to replace existing supplies and meet future demand.[20] The Company provided an outline of the most

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[20] Berkshire also identified proposed distribution project improvements that would allow more reliable utilization of Berkshire's existing and planned supplies. First, as part of the agreement with Altresco for Berkshire to construct the proposed Altresco pipeline, Berkshire stated that it would acquire optional additional transportation of 5,000 million British thermal units ("mmbtu") per day between the Tennessee main line and the Company's Pittsfield market area in Berkshire's territory (Exh. B-1, pp. 12-13). Second, Berkshire identified as a planned facility, to be implemented by the Company within the forecast period, a 2.6-mile expansion of the Northampton distribution line serving the Company's Connecticut River Valley market areas (Exh. HO-1, Tab 2, Table G-21).

important considerations it used when evaluating the resource additions which are included in its current supply plan (Exh. HO-1, Tab 2, pp. 26-30). The Siting Council reviews the Company's process for identifying and evaluating resource additions within three categories: pipeline supplies; supplemental supplies; and conservation.[21] The Siting Council also reviews the Company's process for evaluating additional supplies across resource categories.

i. Pipeline Supplies

Berkshire stated that many resources are available to assist the Company in the identification of prospective gas supply options (Exh. HO-R-20). Among the resources available for identification of supply options, the Company included: membership in gas industry organizations; discussions with other gas companies at industry meetings with suppliers; review of FERC filings; Massachusetts regulatory decisions; and industry publications (id.). The Company indicated that periodic internal management meetings are held to discuss various options and strategies (id.).

The Company identified one planned addition to its pipeline suplies during the forecast period, which is Tennessee's Northeast Expansion Project ("NOREX").[22] The Company provided a list of the most important considerations used in its evaluation of the NOREX project (HO-1, Tab 2, p. 28). The Company's evaluation of this project included

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21/ The Company does not include load management as a supply source in its evaluation outline. However, the Company identified a customer who had previously received firm supply, the University of Massachusetts, Amherst, who is now an interruptible customer -- thus aiding in reducing peak winter supply obligation (Tr. 1, pp. 18, 25, 139-147).

22/ Berkshire stated that, as part of the agreement with Altresco for Berkshire to construct the proposed Altresco pipeline to the planned Altresco cogeneration plant, it would have the option to acquire excess gas not needed by Altresco, at Altresco's delivery cost (Exh. B-1, pp. 13-14). However, these volumes do not represent a firm supply, and are not included in the Company's base case.

price and reliability considerations as well as the additional long-term benefit of enhanced flexibility to contract for peak supplies due to increased take station capacity (id.). In evaluating the cost of the NOREX project, the Company referred to the LaCapra analysis of daily dispatch scenarios, which calculates the effect of substituting NOREX volumes for peaking supplies (see Section III.F.2.a, below) (Exh. HO-S-1S). The Company stated that it favored the NOREX project, in part, because it would provide increased capacity on Tennessee laterals supplying Berkshire take stations located away from the Tennessee main line (Exh. HO-R-28).

In order to refine its planning process, the Company stated that it is finalizing implementation of a long-range financial planning model (id., p. 9). The Company provided sample outputs of the model, and indicated that the model will include modules in which sendout forecasts and gas supply sources can be developed and analyzed (id.; Exh. HO-R-3). Berkshire stated that the model will enable the Company to formally incorporate its sendout forecast into its annual long-range planning process (id.). The Company also cited its development of a load management model and installation of a new electronic measurement system for large customers as planned enhancements to its supply planning process (Exh. HO-R-2; Berkshire Brief, p. 47; Altresco Brief, p. 19). Finally, the Company stated that its internal personnel reorganization has increased the resources available to the resource planning process (Exhs. HO-1, Tab 2, pp. 5, 10; B-1, p. 7)

The Siting Council recognizes that the pipeline supply options available to gas companies are limited by transportation availability. The Company's process for identifying pipeline supply options is appropriate for a medium-sized company considering this limitation. Further, the considerations which the Company employed in its evaluation of the NOREX project, such as cost, reliability, and long-term benefits of system expansion, are appropriate. However, the Siting Council notes that while Berkshire has employed appropriate considerations, this is not a substitute for the consistent application of well-defined criteria.

The Siting Council finds that the Company's process for evaluating pipeline resource options is appropriate for a medium-sized gas company. However, the Siting Council ORDERS Berkshire, in its next forecast filing, to identify specific criteria which it uses to evaluate pipeline supplies, as well as describing how each of those criteria was applied to each pipeline supply identified and evaluated by the Company.

ii. Supplemental Supplies

The Company uses the same process for identification of supplemental supplies that it uses to identify pipeline supplies (Exh. HO-R-20) (see Section III.C.2.b.i, above). As it did for pipeline supplies, the Company provided a list of the most important considerations used to evaluate the planned additions to its supplemental supplies (Exh. HO-1, Tab 2, pp. 27-29).

The Company identified two planned additions to its supplemental supplies: (1) a five-year contract for LNG from Bay State, effective from 1987-88 through 1991-1992; and (2) a one-year contract for LNG from Distrigas, effective from September 1988 through March 1989 (Exhs. HO-R-5; HO-R-6).[23] The Company receives LNG from Bay State and Distrigas via backhaul on Tennessee's system. Berkshire considered the following in evaluating these supplies: (1) cost, which is favorable compared to other peaking supplies; (2) operational benefits due to ability to divert contracted pipeline gas to Tennessee's supply-constrained Northampton lateral; (3) diversification of supply mix; and (4) flexibility of supply on

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[23] Berkshire stated that as part of its agreement with Altresco for Berkshire to construct the proposed Altresco pipeline to the planned Altresco cogeneration plant, it would have the option to acquire up to 3,500 mmbtu of firm peaking supplies from December 15 through February 15 at Altresco's alternate-fuel cost (Exh. B-1, pp. 13-14). However, these volumes are not included in the Company's base case.

a daily basis (id., pp. 27-29). In addition, the Company identified the following benefits specific to the Bay State LNG supply: (1) reliability of supply due to its location near Berkshire's service territory; and (2) the Company's generally favorable experience with Bay State (id., p. 27). The Company also cited Bay State's guarantee of firm transportation capacity on Tennessee's Northampton lateral (Tr. 2, pp. 72-73, 123). The considerations which the Company identified as unique to the Distrigas LNG supply are: (1) no minimum take requirements; and (2) need for some caution due to the foreign control of the supply (Exh. HO-1, Tab 2, pp. 28-29).

The Siting Council notes, as it did for pipeline options, that the supplemental supply options available to gas companies are limited. The Company's process for identifying supplemental supplies is appropriate for a medium-sized company, considering this limitation. Further, the considerations which the Company employed in its evaluation of the Bay State and Distrigas LNG contracts, such as cost and diversification of supply mix, are appropriate. However, as stated in Section III.C.2.b.i, above, listing appropriate considerations is not a substitute for the consistent application of well-defined criteria.

The Siting Council finds that the Company's process for evaluating supplemental supply sources is appropriate for a medium-sized company. However, the Siting Council ORDERS Berkshire, in its next forecast filing, to identify specific criteria which it uses to evaluate supplemental supplies, as well as describing how each of these criteria was applied to each supplemental supply option identified and evaluated by the Company.

iii. Conservation

In the 1987 Berkshire Decision, as noted above, the Siting Council found that the Company failed to establish that it made supply planning decisions pursuant to a process that enabled the Company to evaluate a full range of resource options, including C&LM, and to distinguish among them on the basis of cost (16 DOMSC at 85-86). In its previous decision, the Siting Council also specifically criticized Berkshire for failing to evaluate C&LM programs' potential as possible resource options available to the Company (id.).

Neither in its Forecast nor during the course of evidentiary hearings in this proceeding did the Company set forth any conservation programs that had been identified for evaluation, and instead treated conservation as a generic resource option (Exh. HO-1, Tab 2, p. 29).

In addition to the resources available to the Company to assist in the identification of sources of pipeline and supplemental supply, the Company cited its membership in the Massachusetts Natural Gas Council ("MNGC"), which is in the process of developing a database of conservation programs and activities nationwide, as a resource for identification of potential conservation programs (Exh. HO-R-20; Tr. 1, p. 23).

To evaluate conservation as a resource option, the Company used the following considerations: (1) the "general social policy" in favor of conservation, and societal benefits due to conservation of resources and minimization of environmental impact; (2) the difficulty in quantifying and comparing benefits and cost-effectiveness of additional conservation efforts; (3) the stability of fuel prices which significantly impact conservation; (4) the indirect control of the Company over conservation equipment; and (5) the costs to customers, as well as costs to the Company.[24]

On November 30, 1989, the Massachusetts Department of Public Utilities ("Department" or "MDPU") issued its Order in D.P.U. 89-112 ("MDPU Order"), which required Berkshire to submit a conservation action plan which details "the [conservation] actions which the Company plans to take over the

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[24] The Siting Council notes that although the Company does not identify specific conservation programs in its Forecast, several of its considerations assume specific characteristics of conservation, such as its relationship to the cost of fuel and the degree of Company control over equipment, which may vary among programs.

next two years, covering the steps from development and planning to program implementation" (D.P.U. 89-112, p. 64).[25] Following the MDPU Order, and in light of the Company's failure to identify a single conservation program for evaluation in its Forecast or during the course of evidentiary hearings in this proceeding, staff issued a supplemental information request. The supplemental information request asked the Company to provide to the Siting Council the MDPU-mandated conservation action plan, including a description of how the Company's supply planning process was used to identify and evaluate the programs included in the conservation action plan. In addition to its response to the staff's supplemental information request, the Company provided an updated avoided cost study which reflects the cost of capital allowed in D.P.U. 89-112. (Exhs. HO-R-30, HO-R-30S).

The Company's conservation action plan identifies six goals: (1) to promote cost-effective energy use; (2) to be accessible to a wide number of customers; (3) to develop better data on C&LM; (4) to reduce the need for long-run capacity additions to the Company's gas supply and distribution system; (5) to minimize per household implementation cost; and (6) to minimize the impact on nonparticipating customers (Exh. HO-R-30, Action Plan, p. 2).

As with the Company's Forecast, the conservation action plan cites the compilation of a database of programs being conducted for the MNGC as a source for identification of potential conservation programs (id., Action Plan, p. 1).

In Berkshire's description of how the Company's supply planning process was used to evaluate the conservation programs included in the conservation action plan, Berkshire asserts that questions of cost, reliability and environmental impact were factored in as the program was developed (id., p. 2). Further, the Company stated that the major considerations originally identified in its Forecast for evaluation of

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[25] The Siting Council hereby takes administrative notice of the MDPU Order.

conservation also are reflected in the conservation action plan (id., p. 3).

The Company's conservation action plan describes what the Company calls the four conservation programs which the Company will pursue during the next two years: (1) a low-income residential program which will provide grants up to a certain maximum, and zero or low interest loans to households in need of more conservation investments than the grants will cover; (2) a full residential program which will provide low-interest loans for cost-effective conservation investments; (3) energy audits for commercial/industrial customers; and (4) dialogue with electric companies regarding fuel-switching (id., Action Plan, pp. 4-5).

As the Siting Council has stated in other decisions, the implementation of cost-effective conservation programs is still largely in the developmental stage throughout the gas industry (1989 Bay State Decision, EFSC 88-13, p. 46). Given this level of development, and given the company's status as a medium-sized company under Siting Council standards, the Company's participation in the MNGC effort to identify programs for evaluation is appropriate at this time. Accordingly, the Siting Council finds that the Company's process for identifying potential conservation supplies is appropriate.

While we have found the Company's identification process to be appropriate, the Siting Council has three serious concerns with the process under which Berkshire evaluates conservation programs.

First, although the Company cites the MNGC report as a source for identification of conservation programs, and states that it factored in questions of cost, reliability, and environmental impact when developing its conservation action plan, the Company provides no explicit description of how its evaluation of potential conservation programs resulted in the selection of the four programs identified in the conservation action plan. The Company gives no indication of how the considerations identified in its Forecast and the "questions of cost, reliability, and environmental impact" were weighted and applied to the full range of identified potential conservation programs. In sum, Berkshire failed to present any process by which it evaluates potential conservation programs.

Second, Berkshire identifies as considerations in its evaluation of conservation measures two thinly disguised anti-conservation biases: (1) the difficulty in quantifying and comparing benefits and cost-effectiveness of additional conservation measures; and (2) the Company's lack of direct control over conservation equipment. These considerations are unsupported and this, in and of itself, dictates a finding that Berkshire failed to demonstrate that it applied fully appropriate criteria in its evaluation of conservation programs.

Third, Berkshire fails to specify well-defined criteria which can be applied to all conservation options, and instead lists only considerations which are used in its evaluation of conservation options. As the Siting Council noted in our review of Berkshire's evaluation of traditional supply sources, listing considerations -- even appropriate considerations -- is not an adequate substitute for the consistent application of well-defined criteria.

The Company now has completed an avoided cost study, which is essential to evaluation of conservation and other supply options.[26] But the avoided cost study must be integrated, along with appropriate non-cost factors, into a gas company's supply planning process to be valuable. The record in this proceeding indicates that this has been done, at best, to a very slight degree. Accordingly, the Siting Council finds that the Company has failed to demonstrate that its process for evaluating conservation options is appropriate. The Siting

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26/ The Siting Council has noted in previous decisions that, while evaluating conservation programs based on MDPU-approved avoided cost calculations ensures an appropriate cost comparison, such a process will allow the Company to evaluate conservation options on one basis only. Clearly, other criteria such as timing and ability to serve distribution-constrained areas are critical in comparing conservation options (1989 Bay State Decision, EFSC 88-13, p. 46).

Council ORDERS Berkshire, in its next forecast filing to identify specific criteria which it uses to evaluate conservation programs, to describe how each of these criteria was applied to each conservation option identified and evaluated by the Company, and to demonstrate that an appropriate avoided cost study has been integrated into this process.

iv. Consideration of All Resources on an Equal Footing

The Siting Council has held that in order for a gas company's supply planning process to minimize cost, that process must adequately consider alternative resource additions, including C&LM options, on an equal basis. 1989 Bay State Decision, EFSC 88-13, p. 51; 1989 Fitchburg Decision, EFSC 86-11A, p. 51; 1988 ComGas Decision, 17 DOMSC at 138-139; 1987 Bay State Decision, 16 DOMSC at 323; 1987 Berkshire Decision, 16 DOMSC at 85; 1987 Boston Gas Decision, 16 DOMSC at 252; 1986 Fall River Decision, 15 DOMSC at 115.

The record in this proceeding indicates that Berkshire has become somewhat more responsive to the Siting Council's standard for considering alternative resource options on an equal footing. The Company has now completed an avoided cost study, and provided the results of this study to the Siting Council (Exhs. HO-R-7S; HO-R-30S). Further, the Company has stated that it intends to incorporate the results of the avoided cost study into future forecasts and supply plans to be submitted to the Siting Council, which in turn will be incorporated into the Company's long-range financial modeling system (Exh. HO-R-19).[26]

While the completion of an avoided cost study, in

26/ It bears noting, however, that, although the Company states that it intends to incorporate the results of the avoided cost study into future forecasts and financial modeling, the Company did not provide any schedule for completing these activities and admitted that it must develop a program to convert its split-year Siting Council data to fiscal year data before this process can take place (Exh. HO-R-19).

response to regulatory agency requirements, is an important first step, the Company's present process simply does not consider all resource options on an equal footing. The Company has presented a description of considerations which it applied in its evaluation of each supply source addition (see Section III.C.2, above), but the considerations for evaluating conservation as a supply source differ significantly from its treatment of other, traditional supply sources. In evaluating conservation programs, the Company states that it relies on considerations such as social policy, societal benefits, and environmental impacts, which are not included in its evaluation of traditional supply sources. Further, considerations such as diversity of supply sources, which are used in the Company's evaluation of traditional supply sources, are not included in the Company's evaluation of conservation programs. It is apparent from the record in this case that the Company has been unable to completely free itself from the old, tired excuses regarding C&LM as a resource option. The Siting Council consistently has required that C&LM should be treated equally, but we have yet to see Berkshire take meaningful steps to acknowledge that fact.

Based on the record in this case, the Siting Council finds that Berkshire has failed to treat alternate resource additions on an equal footing with traditional sources of supply.

The results of the Company's avoided cost study are a necessary first step for determining the cost-effectiveness of agas company's C&LM programs relative to other supply options. However, this initial step must be followed by integration of the avoided cost study into the Company's supply planning process. Accordingly, the Siting Council ORDERS Berkshire, in its next forecast filing, to integrate the results of the avoided cost study into its supply planning process.

3. Conclusions on the Supply Planning Process

In the 1987 Berkshire Decision, the Siting Council found that Berkshire failed to establish that it made supply planning decisions pursuant to a process that enabled the Company to evaluate a full range of resource options, including C&LM, and to distinguish among them on the basis of cost (16 DOMSC at 85-86).

In this proceeding, the Siting Council has found that Berkshire's process for identifying and evaluating pipeline and supplemental supply sources is appropriate, and that its process for identifying conservation programs is appropriate. However, the Siting Council has found that the Company has failed to demonstrate that its process for evaluating conservation programs is appropriate, and found that the Company's supply planning process has failed to ensure the treatment of all resource options on an equal footing.

While we recognize that: (1) Berkshire's process for identifying and evaluating traditional supply sources has been found appropriate at this time; (2) implementation of cost-effective conservation programs is still largely in the developmental stage throughout the gas industry; and (3) Berkshire has made some modest improvements in evaluating C&LM, such as completing an avoided cost study, we are deeply concerned that Berkshire still has not developed an acceptable comprehensive planning process. We are particularly concerned that this failure has persisted even after the Siting Council strongly criticized Berkshire's planning process in the 1987 Berkshire Decision. The Siting Council has placed great importance on a planning process in enabling gas companies to make responsible resource decisions. 1989 Bay State Decision, EFSC 88-13, pp. 38-39; 1989 Fitchburg Decision, EFSC 86-11(A), pp. 54-55; 1989 NEES Decision, 18 DOMSC at 336-338, 348-370; 1989 Boston Edison Decision, 18 DOMSC at 224-226, 250-281; 1988 EUA Decision, 18 DOMSC 73, 100-103, 111-131; 1987 Boston Gas Decision, 16 DOMSC at 71-72.

In sum, we are mindful of the improvement the Company has made in certain elements of its supply planning process but we also remain troubled, as discussed above, by the lack of improvements in other areas. Accordingly, the Siting Council makes no finding as to whether the Company's supply planning process enables it to make least-cost supply decisions.

The Siting Council's enabling statute also directs it to balance economic considerations with environmental impacts to ensure that the Commonwealth has a necessary supply of energy. G.L. c. 164, sec. 69H. In the future, the Siting Council directs Berkshire to include an adequate consideration of the environmental impacts of resource options in its supply planning process.

D. 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.E, below, and the cost of the Company's supply plan in Section III.F, below.

Berkshire identified as existing long-term supplies, effective throughout the forecast period, its contractual arrangements for pipeline gas from Tennessee and storage gas from Penn-York Energy Corporation ("Penn-York") and Consolidated Gas Supply Corporation ("Consolidated") (Exh. HO-1, Tab 2, Table G-24). Berkshire indicated that in November 1987 it began receiving a new supply of pipeline gas, to be received throughout the forecast period, from the Boundary Interim Gas Service ("INGS") project (id., pp. 30-31, Table G-24).

Berkshire identified as existing sources for meeting peak load the following: (1) a renegotiated five-year contract with Bay State for LNG, effective through 1991-92; (2) a one-year contract with Distrigas for LNG, effective in 1988-89; and (3) propane from the Company's existing propane storage facilities and a revolving one-year contract for propane with Warren Petroleum Company (id., Table G-24; Exhs. HO-R-5, HO-R-6). The Company stated that the present LNG contract with Bay State replaced an earlier five-year contract with that company (Exh. HO-R-5). However, the Company also stated that, in order to reduce the mandatory volumes it must take from Bay

State, it expects to renegotiate again this contract before its expiration in October 1992 (Exh. HO-1, Tab 2, Table G22; Exh. HO-R-5). With respect to the Distrigas LNG supply, the Company indicated that it expects this resource to be available throughout the forecast period at volumes similar to those contracted for in 1988-89 (Exhs. HO-R-6, HO-RR-16).

Berkshire identified additional resources which, although not included as separate planned resources in the forecast of resources and requirements, represent supply options on which the Company may rely (see Exh. HO-1, Tab 2, Table G22). First, the Company described its current and expected use of spot supplies of pipeline gas as an existing non-firm resource that can be substituted for planned resources when it is available and cost-effective (Exhs. HO-R-26, HO-RR-15). Second, as part of the agreement with Altresco for Berkshire to construct the proposed Altresco pipeline to the planned Altresco cogeneration plant, Berkshire stated that it has the option to acquire the following additional supplies: (1) up to 3,500 mmbtu of firm peaking supplies from December 15 through February 15 at Altresco's alternate-fuel cost (and additional non-firm volumes also may be purchased at this price when available); and (2) gas that may not be needed by Atresco, at Altresco's delivery cost (Exh. B-1, pp. 13-14).

The Company has identified what it terms four conservation programs which it plans to implement during the forecast period.

The first planned conservation program is a low-income residential program which would provide grants and low-interest loans to qualified residents for insulation, weatherization, heating system, and hot water improvements (Exh. HO-R-30). This program will be implemented during the upcoming year as a pilot program in a geographic subsection of Berkshire's service territory, with a target of 100 households (id., Action Plan, pp. 6-8). Berkshire states that as the pilot program is developed and the Company gains experience and data, the program may be modified (id., p. 7). The revised program will then be expanded to one or more additional geographic areas (id.).

The second conservation program identified by the Company is a residential energy efficiency program which will be available to all residential customers, but which will be directed particularly toward high use and other gas heating customers (id., p. 13). This program will consist of low-interest loans for cost-effective conservation improvements (id., pp. 13-14). The Company stated that information gained during the early stages of implementation of the low-income residential program will be used in the development of the residential energy efficiency program (id., p. 13). The Company identified a goal of serving 200 residential customers in the first program year, but did not specify whether this goal includes the 100 customers targeted by the low-income residential program (id., p. 15). The Company stated that the goal for the second year of the program would be based upon experience gained during the first year (id.).

The third conservation program identified by the Company is a walk-through audit program for commercial and industrial customers (id., p. 18). This program is designed to provide information to commercial and industrial customers through a formalized audit program and a follow-up procedure to determine whether customers have responded to the audit results (id.). The Company stated that the first year of the program will consist of audits and research into a wider menu of C&LM programs for commercial and industrial customers (id.).

Finally, the Company also listed as a C&LM program a planned dialogue with electric utilities in its service area to discuss fuel-switching potential in regard to electric C&LM programs (id., p. 19). According to the Company, this dialogue will begin within three months of the Company's submission of its conservation action plan (id.).

The Company's supply plan does not directly include any resources from conservation programs. In Section F, below, the Siting Council evaluates the impact of this approach on the cost of the Company's supply plan.

E. Adequacy of Supply

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 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, Berkshire must have adequate supplies to meet several types of requirements. Berkshire's primary service obligation is to meet the requirements of its firm customers. To the extent possible, Berkshire also supplies gas to its interruptible customers.

a. Base Case Analysis

The Company's base case, normal year supply plan demonstrates that the Company has adequate supplies to meet forecasted normal year requirements throughout the forecast period (Exh. HO-1, Table G-22D). Accordingly, the Siting Council finds that Berkshire has established that its base case, normal year supply plan is adequate.

Berkshire's forecasted design year firm sendout requirements and base case supply plan for the heating season are summarized in Table 2.[27] In all years of the forecast

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[27] The base case supply plan includes gas supply from the NOREX Project beginning in 1990-1991 (Exh. HO-1, Table G-22D; Tr. 2, p. 90). The base case supply plan does not include any forecasted gas savings from Berkshire's C&LM programs (id.). Although Berkshire does not include its full propane storage volumes in its base case supply plan for the years listed, these volumes would still be available to the Company if the Company should require them.

period, the Company's base case supply plan would meet its forecasted design year requirements. Accordingly, the Siting Council finds that Berkshire has established that its base case, design year supply plan is adequate.

b. Contingency Analysis

As described above, the Company's base case includes supplies which are not yet in place and which require both permitting and construction activities outside the Company's control (see Section III.D.1, above). In addition, the Company's base case includes LNG volumes from a supplier who obtains its supply overseas and who previously has experienced supply disruptions. 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 one-year delay in delivery of the NOREX volumes; and (2) a disruption in Distrigas LNG volumes.

i. One-Year Delay in NOREX Project

Berkshire stated that its expected in-service date for Tennessee's NOREX Project is November 1990 (Tr. 2, p. 90). If the NOREX Project is delayed by one year, and if all other resources in the base case supply plan remain available to the Company, Berkshire stated that it would meet its design year requirements in 1990-91 through increased reliance on storage gas, Bay State Gas Company's LNG volumes, and on increased use of propane (Tr. 2, p. 98; see also Exh. HO-2A, Table G22D).[28]

Based on the foregoing, the Siting Council finds that Berkshire has adequate resources to meet forecasted firm design year sendout requirements in the event of a one-year delay in the NOREX Project.

ii. Disruption in Distrigas LNG Deliveries

Berkshire stated that it contracted for 39 mmcf of LNG

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[28] The Siting Council assumes that Berkshire would obtain spot propane purchases to fill its propane storage facilities before the 1990-91 heating season.

from Distrigas in 1988-89, and expects to contract for similar volumes in each of the later years of the forecast period (Exh. HO-1, Tab 2, Table G24; Tr. 2, pp. 110-111). Berkshire relies on Distrigas LNG to meet approximately one percent of its design year firm sendout requirements during the forecast period (Exh. HO-1, Tab 2, Table G-22D).

The Company stated that it would cover a loss of its planned Distrigas volumes by taking the following steps: (1) attempting to secure additional LNG volumes from the Bay State Gas Company;[29] (2) attempting to store additional pipeline gas during non-peak periods for peak use; and (3) making arrangements to use additional propane from its propane plants (Tr. 2, pp. 113-114).

In light of the limited volumes that Berkshire would require in the event that LNG supplies are not available from Distrigas during the forecast period, the Siting Council finds that, based on this record, Berkshire has established that it has adequate resources to meet forecasted firm design year requirements in the event of a disruption in Distrigas LNG deliveries.

2. Design Day Adequacy

Berkshire 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 peak day.

29/ The Company stated that it expects to renegotiate its existing contract with Bay State to reduce mandatory LNG volumes beginning in 1990-91 (Exh. HO-1, Tab 2, Table G22D). However, the Company stated that, if it appeared Distrigas LNG volumes would be unavailable during that year, the Company would not reduce its mandatory volumes from Bay State (Tr. 2, p. 113).

a. Base Case Analysis

Berkshire's forecasted firm design day sendout requirements and base case supply plan are summarized in Table 3, below. The base case supply plan includes the gas supply from the NOREX Project beginning in 1990-1991 (Exh. HO-R-12; Tr. 2, p. 90).[30] In each year of the forecast period, the Company's base case supply plan would meet forecasted firm design day requirements (id.).

Accordingly, the Siting Council finds that Berkshire has established that its base case supply plan is adequate.

b. Contingency Analysis

i. One-Year Delay in NOREX Project

Berkshire stated that the expected in-service date for the NOREX Project is November 1990 (Tr. 2, p. 90). If all other resources in the base case supply plan remain available to the Company, Berkshire would not realize a resource deficiency in the forecast period in the event of a one-year delay in the NOREX Project (see Table 3, below).

Accordingly, the Siting Council finds that Berkshire has established that it has adequate resources to meet its forecasted firm design day requirements in each year of the forecast period in the event of a one-year delay in the NOREX Project.

ii. Disruption in Distrigas LNG Deliveries

Berkshire relies on Distrigas LNG to supply 3 mmcf of its firm design day requirements over the forecast period (Exh. HO-R-12; Exh. HO-R-28; Tr. 3, Tr. 2, pp. 123-124).[31] If all

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[30] As indicated above, the base case supply plan does not include any forecasted gas savings from any Berkshire C&LM program (Exh. HO-R-12).

[31] Berkshire stated that its maximum daily LNG volumes are approximately 3 mmcf under the Distrigas contract and 4 mmcf under the Bay State contract, but noted that best-efforts transportation constraints on Tennessee's laterals currently limit Berkshire to a total of approximately 6 mmcf in LNG volumes on a design day (Exh. HO-R-28; Tr. 2, pp. 123-124). Therefore, loss of Distrigas LNG volumes would reduce total LNG volumes by only 2 mmcf, from 6 mmcf to 4 mmcf, in 1989-90. In later years, the NOREX project will remove the transportation constraint.

other resources in the base case supply plan remain available to the Company, Berkshire would not realize a resource deficiency in the forecast period in the event of a disruption in its Distrigas LNG volumes (see Table 3, below).

Accordingly, based on this review, the Siting Council finds that Berkshire has established that it has adequate resources to meet its firm design day sendout requirements in all years of the forecast period in the event that LNG supplies are not available from Distrigas.

3. Cold-Snap Adequacy

The Siting Council has defined a cold-snap as a prolonged series of days at or near design conditions. 1989 Bay State Decision, EFSC 88-13, p. 75; 1986 Fitchburg Decision, 15 DOMSC at 58. 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. 1988 ComGas Decision, 17 DOMSC at 137; 1987 Berkshire Decision, 16 DOMSC at 79.

In the 1987 Berkshire Decision, the Siting Council found that Berkshire had adequate resources to meet its firm forecasted sendout requirements under cold-snap conditions, but ordered Berkshire to include an updated cold-snap analysis in its next filing (16 DOMSC at 80). Berkshire provided an updated cold-snap analysis in its current filing, and indicated that the Company's ability to respond to prolonged cold-weather conditions had been improved since the previous decision, due to the addition of Boundary and Distrigas volumes (Exh. HO-1, Tab 2, p. 34-35).

Berkshire stated that it could meet a cold-snap of eight to 14 days based on approximately 30 mmcf of daily volumes that can be delivered by pipeline and 14 mmcf of daily volumes that can be produced from the Company's five propane plants (id.). The Company stated that its propane storage capacity of 65.5 mmcf represents a five-to-six day supply during a cold-snap (id., p. 35, Table G14).

Accordingly, the Siting Council finds that Berkshire has established that it has adequate resources to meet its forecasted firm sendout requirements under cold-snap conditions. Further, the Siting Council finds that Berkshire has complied with the order in our previous decision requiring the Company to submit an updated cold snap analysis.

4. Conclusions on the Adequacy of Supply

The Siting Council has found that Berkshire has established that: (1) it has adequate resources to meet its forecasted firm normal year, design year, and design day sendout requirements throughout the forecast period; and (2) it has adequate resources to meet its forecasted firm sendout requirements under cold snap conditions throughout the forecast period.

Accordingly, the Siting Council finds that Berkshire has established that it has adequate resources to meet its firm sendout requirements throughout the forecast period.

F. Least Cost Supply

1. Standard of Review

As set forth in Section III.C.2, 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. 1989 Bay State Decision, EFSC 88-13, p. 80; 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; see 1989 NEES Decision, 18 DOMSC at 337. A gas company must establish that application of its supply planning process -- including adequate consideration of conservation and load management 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 prior to selection of major new resources for their supply plans. 1989 Bay State Decision, EFSC 88-13, p. 80; 1989 Fitchburg Decision, EFSC 86-11(A), p. 52; 1987 Bay State Decision, 16 DOMSC at 319; 1986 Gas Generic Order, 14 DOMSC at 100-102.

2. Supply Cost Analysis

In the previous Berkshire decision, the Siting Council found that the Company (1) failed to perform cost studies as required in earlier Siting Council orders and (2) failed to establish that the NOREX and Boundary projects represent least-cost additions to the Company's supply plan. 1987 Berkshire Decision, 16 DOMSC at 83-85. Consistent with its Decision in the 1986 Gas Generic Order, the Siting Council requires the performance of cost studies regarding the supply plan, and specific showings that any additions to a company's supply plan are least-cost, in order to ensure that a company's overall supply plan minimizes cost.

In the instant case, the Company is obligated to perform cost studies that support Berkshire's decision to add new resources during the five-year forecast period -- including the Tennessee NOREX project, Bay State LNG supply and Distrigas LNG supply.[32] Such cost studies are required in order to evaluate whether these new resources are least-cost additions to the Company's existing supply plan, taking adequacy and reliability concerns into account.

The overall supply planning process the Company used in making supply decisions such as these and the impact of the decisions on the adequacy of the Company's supply plan have been reviewed above (see Sections III.C and III.D, above). Here, the Siting Council reviews the Company's actual application of its supply planning process in making specific

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32/ The Siting Council does not review the Boundary project as an additional resource in this proceeding because it was included in Berkshire's previous filing, and it was in place at the beginning of the forecast period.

supply decisions to determine if application of that process resulted in a least-cost resource plan.

a. NOREX Project

Tennessee's NOREX project was included as a resource addition in the Company's previous filing. In its review of that filing, the Siting Council found that the Company had failed to perform cost studies to demonstrate that NOREX represented a least-cost resource addition prior to its selection of the NOREX project (1987 Berkshire Decision, 16 DOMSC at 83-85). Accordingly, in our current review, the Siting Council does not evaluate whether the Company completed comprehensive cost studies prior to its selection of the NOREX project as a major new resource addition to its supply plan. Instead, the Siting Council reviews whether the Company has performed comprehensive cost studies to evaluate whether the NOREX volumes, as a new resource, will represent a least-cost supply resource.

In support of the NOREX project as a least-cost addition to its supply plan, the Company provided a copy of the analysis that it submitted to FERC of the benefits NOREX already would have provided in two recent years if it had been available, and the benefits that it would provide in the next three years if available (Exh. HO-RR-14). The Company estimated these benefits in terms of the heating season volumes of peaking supplies potentially displaced by NOREX in the respective years (id.).

In its analysis for FERC, the Company indicated that the NOREX project would have reduced Berkshire's use of peaking supplies by 384 mmcf[33] in the 1986-87 heating season and 345 mmcf in the 1987-88 heating season (id.). To illustrate its methodology for estimating peaking supply savings in those two years, the Company provided load duration plots for 1986-87 and 1987-88 (Exh. HO-RR-11). For the forecast years after NOREX

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[33] In its analysis, the Company assumed that 1 mmcf is equivalent to 1033 dekatherms ("dth") (Exh. HO-RR-11).

is expected to become available, Berkshire estimated peaking supply savings of 464 mmcf in the 1990-91 heating season and 487 mmcf in the 1991-92 heating season. However, the Company did not provide supporting load duration assumptions for the projected years 1990-91 and 1991-92 (Exh. HO-RR-14).

In further support of the NOREX project as a least-cost addition to the Company's supply plan, Berkshire provided the LaCapra analysis, which the Company submitted as a check on the assumptions made in its current forecast and supply plan (see Section II.C.3.a, above). The LaCapra analysis includes cost studies which assess the Company's overall mix of supplies both with and without the NOREX project (Exh. HO-S-1S). The LaCapra analysis compares the actual cost, including demand cost and gas cost per thousand cubic feet ("mcf"), of Berkshire's supplies in 1987-88 with the projected cost of Berkshire's supplies in 1991-92 (id.). The analysis projects the 1991-92 split-year dispatch of Berkshire's respective supplies both with and without the NOREX project (id.).

The LaCapra analysis extends beyond the scope of the Company's own studies to assess Berkshire's systemwide average and marginal costs in 1987-88 (based on that year's actual number of customers and resource price levels) and 1991-92 (based on the projected number of customers and resource price levels), assuming a typical mix of daily DD experience consistent in aggregate with a normal year (id., p. 4, Appendices G and I). For 1991-92, the LaCapra analysis presents calculations of average and marginal systemwide costs to compare Berkshire's supply plan both with and without the NOREX project (id., Appendices H and I).

According to the LaCapra analysis, without NOREX Berkshire's heating season costs would increase as follows: (1) average commodity cost increases from $2.82 to $3.06 per mcf; (2) average demand cost increases from $0.85 to $1.19 per mcf; and (3) marginal commoditiy cost increases from $3.21 to $4.41 per mcf (id., Appendices G and I).

If NOREX becomes available as planned, the analysis demonstrates that the average commodity cost and marginal commodity cost would increase less in 1991-92 with NOREX than they would without NOREX.[34] The average commodity cost would increase 17 cents per mcf less with NOREX (to $2.89 rather than $3.06 per mcf) and the marginal commodity cost would increase 94 cents per mcf less with NOREX (to $3.47 rather than $4.41 per mcf). The analysis also shows that the average demand cost would increase 21 cents per mcf more with NOREX (to $1.40 rather than $1.19 per mcf). Thus, while the NOREX project would significantly reduce projected increases in marginal costs, the changes in projected average demand cost and average commodity cost would be nearly offsetting for the sendout levels expected in 1991-92.

The Siting Council notes that, in order to support its position that the NOREX project was least-cost, the Company initially relied on its submissions to FERC reflecting estimates of the peaking supply resources that NOREX volumes would replace under both recent and projected sendout in the Berkshire system (Exh. HO-RR-14; Tr. 2, pp. 55-60, 78-80). These estimates of resource substitution, based on daily dispatch scenarios over heating season periods, clearly are a necessary first step to understanding cost trade-offs. However, the Company implicitly assumed that the substitution of pipeline supplies for peaking supplies is consistent with least-cost supply planning. The Company did not determine the cost impact of the substitution -- including both demand cost and commodity cost changes. Therefore, the analysis does not represent an appropriate cost evaluation of whether the NOREX project is a least-cost resource addition to the supply plan.

The Company also provided the LaCapra analysis, which addresses the effect on systemwide cost of substituting NOREX volumes for peaking supplies in the last year of the forecast. By projecting comparative average and marginal cost for the

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[34] The LaCapra analysis assumes that Berkshire would use 411,591 mcf of NOREX volumes in the split year 1991-92, of which 405,377 mcf would be used in the heating season to replace existing peaking supplies (Exh. HO-S-1S, Appendices H and I).

Berkshire system with and without the NOREX project, the LaCapra analysis provides significant insight into the cost-effectiveness of the NOREX project. As such, the LaCapra analysis represents a cost study that uses appropriate techniques to address the extent to which the NOREX project is a least-cost addition to the supply plan. However, because the LaCapra analysis only projects costs through 1991-92, it fails to assess the cost implications of NOREX throughout the 20-year life of the contract.

The LaCapra analysis demonstrates that Berkshire's systemwide normal year supply cost will not be reduced within the forecast period by the addition of the NOREX project. Rather, the average cost per mcf of sendout in 1991-92 -- including average demand cost and average commodity cost combined -- is projected to be four cents higher with NOREX than without NOREX (Exh. HO-S-1S, Appendices H, I). Although the NOREX project increases expected 1991-92 normal year cost, the LaCapra analysis states that 1991-92 design year cost would be reduced by the NOREX project (Exh. HO-S-1S, p. 8). Additionally, the marginal cost of an incremental mcf of sendout, calculated for the 1991-92 sendout level, is projected to be $0.94 lower with NOREX than without NOREX (id.). Thus, it appears the addition of the NOREX project will provide a net cost reduction for Berkshire if and when sendout increases to a level only slightly above that forecast for 1991-92 (id.). However, because the LaCapra analysis does not extend beyond 1991-92, the Company has not provided a quantified analysis of the long-term cost implications of NOREX.

A further concern of the Siting Council is that the Company failed to provide a cost study comparison between the NOREX project and an alternative new supply resource. Instead, the Company only provided the LaCapra comparison between NOREX and existing peaking supplies. While the Siting Council has noted that relatively few gas supply options may be available at a given time, the Company has failed to demonstrate that no other supply options, including C&LM, were available, or that at a minimum, the Company could not have compared the planned volumetric limitations under the NOREX project and alternative limitations that Berkshire might have contracted under the same project. By failing to consider relative costs of either alternative available resources or alternative possible sizes for the NOREX project, the Company cannot determine whether the project is a least-cost addition to the supply plan.

The Siting Council notes that the Company's submission of the LaCapra analysis is a substantial improvement in the Company's assessment of the cost implications of its addition of the NOREX project since its previous filing with the Siting Council. Additionally, the Siting Council notes that medium-sized companies such as Berkshire are not expected to submit cost analyses of the same level of sophistication as the largest gas companies. However, in the future, when large increments of baseload pipeline supplies are added to the Company's supply plan, the Company will be required to establish and fully document that it has identified and thoroughly evaluated, including completion of cost studies, a full range of options including conservation and load management in applying its supply planning process.

In light of the improvement in the Company's analysis of the cost of the NOREX project since the previous filing, and in light of the indication that the project will produce long-term cost savings, the Siting Council finds that Berkshire properly applied its supply planning process in evaluating the NOREX project and that the addition of the NOREX project contributes to a least-cost supply plan.

b. LNG Contracts

The Company identified a five-year contract with Bay State and a one-year contract with Distrigas as planned resources in its current supply plan. Given that neither of these LNG contracts was included as a planned resource in the previous Siting Council review, the Siting Council considers both LNG sources to be planned additions to the supply plan for purposes of the instant review.

The Company failed to provide a cost study in support of the planned addition of either the Bay State LNG supply or the Distrigas LNG supply. The comparative costs provided in the Company's Supply-Price Comparison Table and in the LaCapra analysis provide the only quantitative basis for considering the cost-effectiveness of these supplies.

With respect to its decision to contract for a five-year supply of Bay State LNG, Berkshire indicated that as recently as February 1988 it had been assuming that the NOREX project would be unavailable during the forecast period (Exh. HO-2A; Tr. 2, p. 98). Additionally, the Company stated that its Bay State contract includes an important reliability advantage -- Bay State will make available its transportation rights on Tennessee's Northampton lateral whenever requested by Berkshire, which will allow firm delivery to Berkshire's Northampton lateral take stations of up to 2,000 mcf per day of Bay State LNG supply (Tr. 2, p. 71). Finally, the Company noted that, until recently, Distrigas had not been viewed as a fully reliable source (Tr. 2, pp. 108-109).

The Company stated that the recent availability of the Distrigas LNG supply led the Company to compare the cost of that resource with the cost of utilizing other supplies, including Bay State LNG volumes (Tr. 2, pp. 70-71). The Company stated it determined that, on a cost basis, Distrigas volumes would provide a more desirable supply than Bay State volumes (id., p. 71).

The cost information included in the record provides some insight as to the relative cost of the Bay State LNG and the Distrigas LNG volumes. Based on both the Supply-Price Comparison Table and the LaCapra analysis of estimated dispatch for current (1987-88) load (with assumed "typical" normal year DD pattern), the Bay State LNG supply is more than $1.50 per mcf (demand cost and commodity cost combined) more expensive than the Distrigas LNG supply (Exh, HO-1, Tab 2, supplemental table following Table G24; Exh. HO-S-1S). Based on the LaCapra analysis of estimated 1991-92 dispatch for its assumed normal year DD pattern, the Bay State LNG supply will be more than $2.00 per mcf more expensive than the Distrigas LNG supply for two dispatch scenarios -- one which assumes and the other which does not assume availability of the NOREX project (Exh. HO-S-1S).

The Company ackowledged that its ability to choose Distrigas LNG volumes over Bay State LNG volumes was constrained, given that it evaluated the Distrigas contract when the Bay State contract already had been signed with minimum take-or-pay provisions (id.). However, the Company stated that it expects to renegotiate the Bay State LNG contract to reduce the mandatory volumes (Exh. HO-1, Tab 2, Table G22). Berkhire's ability to substitute Distrigas LNG volumes for already-contracted-for Bay State volumes is limited to (1) the 30,000 mcf in optional volumes under the Bay State contract, and (2) the portion of the 90,000 mcf in mandatory volumes that Berkshire believes it can avoid taking through renegotiation of the Bay State LNG contract.

In sum, the acquisition of the Distrigas LNG supply provides Berkshire with a low-cost resource, as well as a flexible resource that does not lock the Company into a long-term commitment. Notwithstanding the Company's failure to provide a formal cost study of this resource addition, the planned Distrigas LNG supply is consistent with a least-cost planning approach.

The acquisition of the Bay State LNG supply clearly raises more questions with regard to whether the supply is consistent with least-cost planning. The reliability benefits identified by the Company -- including the need for a backup to the NOREX project and the firm delivery capability on the Northampton lateral -- do need to be balanced with the higher cost of Bay State LNG. However, the per unit cost of the Bay State LNG supply, relative to Berkshire's other existing resources and resource options, is of a magnitude which warrants a formal cost study to justify the choice and size of that resource addition.

While a cost study of the respective LNG resource additions would have been appropriate, the Siting Council notes that Berkshire, as a medium-sized company, is not expected to submit cost analyses of the same level of sophistication as the largest gas companies. The Siting Council also notes that the LaCapra analysis of system cost in the last year of the forecast, under an assumed normal year daily dispatch of base case gas supplies, represents a significant improvement since the previous Berkshire forecast review. Further, the Company identified important reliability advantages of its current Bay State LNG supply over the years of the current contract. Accordingly, the Siting Council finds that Berkshire properly applied its supply planning process in reaching decisions on the Bay State LNG supply and the Distrigas LNG supply and that the addition of these supplies contributes to a least-cost supply plan. However, in the future, when large increments of supplemental supplies are added to the Company's supply plan, the Company will be required to establish and fully document that it has identified and thoroughly evaluated, including completion of cost studies, a full range of options including conservation and load management in applying its supply planning process.

c. Conservation and Load Management

As discussed in detail in Section III.C.2.b.iii, above, Berkshire did not identify any specific conservation measures in its Forecast or during the course of evidentiary hearings in this proceeding. However, in response to a supplemental information request, the Company identified four conservation programs which are in varying stages of development and implementation. In addition, the Company provided an avoided cost study which has been updated to reflect the cost of capital allowed in the most recent MDPU Order.

The four programs identified by the Company are: (1) a low-income residential energy efficiency program; (2) a residential energy efficiency program which is not restricted by income requirements; (3) a commercial and industrial walk-through audit program; and (4) a dialogue with electric utilities regarding potential fuel-switching in conjunction with electric C&LM programs (Exh. HO-R-30).

Berkshire has screened potential low-income residential conservation measures for cost-effectiveness (Exh. HO-R-30, Action Plan, Tables 2A, 2B, and 2C). Additionally, the Company stated that information gathered for the low-income residential energy efficiency program would be applied in the development of the full residential energy efficiency program (id., p. 13).

To screen the cost-effectiveness of potential low-income residential conservation measures, the Company calculated the cost per mcf of conserved energy for each measure (id., Tables 2A, 2B, and 2C).[35] This calculation of total cost per mcf included program implementation costs, which would not be passed on to the customer, as well as the cost of the measure itself (id.). The total cost per mcf was then compared to the avoided cost of that mcf, based upon the life of the measure, and whether it would represent a baseload or peaking supply (id.). A pass/fail determination was then made on the cost-effectiveness of the measure based on whether its total cost was above or below the avoided cost (id.). Finally, the Company combined individual measures to determine whether packages of conservation measures were cost-effective, even though the individual measures within the packages may not have been cost-effective on a stand-alone basis (id.).

The Company stated that the benefit structure for implementing cost-effective low-income residential conservation measures will be differentiated between single-family homeowners and multi-family dwellings (id., p. 12). Single-family homeowners will be provided with grants for cost-effective measures up to a maximum of $1,500 (id.). Cost-effective measures above the $1,500 ceiling will be

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[35]/ The specific measures screened by the Company were separated into three categories: (1) thermal envelope measures (air sealing, wall insulation, attic insulation, and storm windows); (2) heating system measures (setback thermostat, replacement of converted coal systems, replacement of broken or inoperable systems, heating system retrofits, and maintenance and tune-ups); and (3) hot water measures (hot water tank wrap, low-flow showerheads, faucet aerators, and temperature setback) (Exh. HO-R-30, Action Plan, pp. 10-12).

subsidized through a zero interest loan, up to an additional $1,000 (id.). For multi-family dwellings, the Company will provide grants to the property owner of up to $375 per low-income tenant, up to a maximum of $1,500 (id.). Cost-effective measures above the $1,500 ceiling will be subsidized by a low-interest loan to the property owner up to a maximum of an additional $1,500 (id.).

The Company has not conducted any cost-effectiveness studies for the commercial and industrial walk-through audit program or the fuel-switching dialogue with electric utilities.

The Siting Council notes that Berkshire has shown some improvement in its ability to incorporate conservation and load management into its supply plan by presenting a completed avoided cost study, as well as, in its response to the supplemental information request, planned C&LM programs. The avoided cost study is an important first step in developing an acceptable supply planning process. The Company has applied its avoided cost study to determine which conservation measures to include in its low-income residential energy efficiency program. By evaluating these measures on an avoided cost basis, the Company has established that programs that include these measures have the potential to reduce the overall cost of supply.[36]

However, the Siting Council previously has found that Berkshire has failed to demonstrate that its process for evaluating conservation options is appropriate (see Section III.C.2.b.iii, above). Without an appropriate supply planning process, the Siting Council cannot determine that the conservation measures selected by the Company on the basis of

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36/ The Company identified a fourth activity, a dialogue with electric utilities within its service territory regarding fuel-switching potential in conjunction with electric C&LM programs, which, as described, is at such an early and insufficiently defined stage that it can hardly be considered a program. Therefore, while the dialogue mentioned may at some point result in a program, we cannot now make any determination regarding the likelihood that this dialogue will reduce the overall cost of supply.

the avoided cost study are in fact lowest cost. Additionally, the design and plans for implementation of the conservation programs identified by the Company raise the following serious concerns.

First, the Company has not demonstrated that its investment in the measures included in the low-income residential energy efficiency conservation program will maximize savings. That is, the Company has not demonstrated that the spending limits incorporated in the program benefit structure are designed to achieve an optimal level of conservation investment, either at the pilot stage or once full program implementation has been achieved. Further, the Company has not identified the total investment which will result from its low-income residential conservation measures, in part because the Company has not identified the total number of households to which the program ultimately will be available.

Second, Berkshire has not provided sufficient information regarding the full residential energy efficiency conservation program to determine the scope of the program, or to establish that its investment in this program will maximize savings. Berkshire has not identified the measures which will be included in this program, the time frame for implementation, the number of households which ultimately will be reached, or the program's benefit structure. Thus, the Company has not demonstrated that the full residential energy efficiency program is designed to achieve an optimal level of conservation investment either at the pilot stage or once full program implementation has been achieved.

Third, the commercial and industrial walk-through audit program suffers from the same lack of documentation as the full residential energy efficiency program. Further, the Company has not identified the potential savings which could be achieved by providing low-interest loans or other incentives at the beginning of the program, rather than waiting to see the results of the informational audits. Additionally, the Company has not indicated whether new commercial and industrial customers will be provided with a walk-through audit before they begin to receive gas service.

Fourth, the projected savings from the planned conservation programs are not included in the Company's base case supply plan. In recent decisions regarding gas companies' supply plans, the Siting Council has stated that there is no apparent reason for gas companies to exclude conservation and load management from their base case resource plans, noting that conservation measures are fully capable of providing gas companies with cost-effective, reliable resources (see 1989 Bay State Decision, EFSC 88-13, p. 89; 1989 Fitchburg Decision, EFSC 86-11(A), p. 42). The Siting Council acknowledges that Berkshire presented its C&LM programs in response to a supplemental information request which was submitted after the close of hearings in this proceeding, and therefore the Company did not include these programs in the base case supply plan set forth in its Forecast. However, the Siting Council ORDERS Berkshire, in its next forecast filing, to: (1) quantify the savings of its existing and planned conservation programs over the forecast period; and (2) fully incorporate these estimates into its base case resource plan and its analyses of adequacy for normal and design conditions.

In addition, the Siting Council notes that C&LM programs are not exempt from the Siting Council's requirements under the 1986 Gas Generic Order (14 DOMSC at 102), that gas companies complete comprehensive cost studies comparing the costs of a reasonable range of practical supply alternatives in their analysis of major new supply options. This requirement holds for large increments of new C&LM just as it does for traditional supply options. A cost study should play a significant role in a gas company's decisionmaking process for acquiring large incremental supplies of C&LM resources.

Based on the record at this time, the Siting Council would have no choice but to find that the Company's C&LM decisions fail to contribute to a least-cost supply plan. While that would be our finding on the information already provided to us, we are mindful that the Company has demonstrated some progress in this area and that the submittal of certain additional information likely could alter this conclusion. We also are mindful that documentation regarding Berkshire's conservation programs was provided very late in this proceeding, thereby depriving the Siting Council of the opportunity to acquire additional information regarding the Company's conservation programs through the discovery and hearing process. Therefore, we find that the Company's supply decisions related to C&LM contribute to a least-cost supply plan if (1) the Company completely and adequately complies with the following conditions and (2) the Siting Council staff verifies that the responses are complete and adequate. At such time that the Hearing Officer in this case shall verify that the responses are complete and adequate, those responses shall be filed in the docket in this proceeding and the finding that the C&LM supply decisions contribute to a least-cost supply plan shall be entered.

CONDITIONS

(1) With respect to the Company's low-income residential energy efficiency program and full residential energy efficiency program, the Company shall:

(a) identify the number of low-income residential customers in the area targeted by the pilot program and in the Company's service territory as a whole;

(b) quantify the total investment and savings (in mcf per year) of the pilot program and estimate the total investment and savings of the fully implemented program. (The response to this condition shall include a description of the methodology by which the Company calculated total investment and savings);

(c) quantify the total investment and savings (in mcf per year) of the pilot program and estimate the total investment and savings of the fully implemented program if the Company invested in all conservation measures in the pilot program which are at or below the Company's avoided cost (i.e., if the pilot program's benefit structure did not include spending limits). (The response to this condition shall include a description of the methodology by which the Company calculated total investment and savings);

(d) based on the results of the comparison of (b) and (c), above, justify, in terms of least-cost planning, the inclusion of the spending limits incorporated in the benefit structure of the pilot program (as well as the amounts chosen for the spending limits) which restrict investment in all cost-effective conservation measures within the pilot program.

(e) present and justify, based on the analysis set forth in 1(a)-(d), above, any restructuring of the low-income pilot program which enables the Company to maximize its savings by investing in all conservation measures within the pilot program which are at or below the Company's avoided cost; and

(f) describe how the Company intends to monitor the results of the pilot program and integrate those results into the final design of the low-income residential energy efficiency conservation program and the full residential energy efficiency program, including a schedule for integration of the pilot progam results into the low-income and full residential programs, and implementation of those programs.

(2) For the commercial and industrial walk-through audit program, the Company shall describe how the Company intends to monitor the results of the informational audits, by what criteria the Company will determine whether additional incentives are necessary to ensure the installation of cost-effective conservation measures, and present a schedule of when this determination will be made. Finally, the Company shall indicate whether an audit will be performed for potential commercial and industrial customers before they begin to receive gas service, and if such audits will not be performed, provide an explanation of why they will not be performed in terms of least-cost planning.

3. Conclusions on Least-Cost Supply

The Siting Council has found that Berkshire properly applied its supply planning process in reaching decisions regarding the NOREX project, the Bay State LNG supply and the Distrigas LNG supply. The Siting Council also has found that each of these supply decisions contributes to a least-cost supply mix.

In addition, the Siting Council has found that the Company's supply decisions related to C&LM contribute to a least-cost supply mix predicated upon (1) the Company's complete and adequate compliance with the conditions contained in Section III.F.2.c, above and (2) the Siting Council staff's verification that the responses are complete and adequate.

Accordingly, should the Company fulfill the conditions set forth above in Section III.F.2.c, above, the Siting Council finds that the Company has established that its supply decisions contribute to a least-cost supply plan.

The Siting Council ORDERS Berkshire in its next forecast filing to analyze the cost-effectiveness of all resource additions as part of total system cost in the context of a framework that analyzes the cost-effectiveness of resource additions, including C&LM, and weighs all resource additions on an equal footing.

G. Conclusions on the Supply Plan

The Siting Council has: (1) made no finding as to whether Berkshire's supply planning process enables it to make least-cost supply decisions; (2) found that Berkshire has established that it has adequate resources to meet its firm sendout requirements throughout the forecast period; and (3) found that Berkshire has established that its supply decisions contribute to a least-cost supply plan, upon compliance with the conditions listed in Section III.F.2.c, above.

The Company in this case has taken some initial steps toward adopting an appropriate planning process and least cost supply plan. However, progress in actually implementing an appropriate planning process which can be applied to evaluate, on an equal footing, all options which will contribute to a least-cost supply plan have been difficult to detect or have been painfully slow in occurring.

Many gas companies, especially smaller ones such as Berkshire, have been willing make some appropriate adjustment to the manner in which traditional sources of supply are judged. But, there remains significant resistance to adopting an appropriate process for judging C&LM and comparing it to traditional supply options.

In this instance, we have chosen to focus on the positive aspects of Berkshire's supply plan. But we must emphasize that, even upon compliance with the conditions set forth by the Siting Council and subsequent approval of the supply plan, the Company must redouble its efforts to fully integrate C&LM into a supply planning process which ensures the treatment of all resource options on an equal footing, and which enables the Company to make least-cost decisions.

Accordingly, the Siting Council hereby APPROVES, upon compliance with the conditions set forth in Section III.F.2.c, above, the supply plan of the Berkshire Gas Company.

IV. DECISION AND ORDER

The Siting Council hereby (1) APPROVES the sendout forecast and (2) APPROVES the supply plan of Berkshire Gas Company upon compliance with the conditions listed above in Section III.F.2.c.

Further, the Siting Council ORDERS Berkshire in its next forecast filing:

(1) to provide an analysis of the availability of existing Connecticut River Valley weather data and the potential to use the first two or three years of Greenfield data to calibrate the existing Connecticut River Valley data for use in a segmented forecast;

(2) to submit statistically derived design year and design day standards;

(3) to submit an analysis of the cost implications of at least two differing levels of reliability of supply as part of its selection of a design year standard and a design day standard;

(4) to provide summaries of sales representatives' reports including quantified trends and expectations in customer numbers over five-year forecast periods, as compiled for at least the two most recent internal reporting cycles; or, in the alternative, to adopt another appropriate, reliable manner for forecasting customer numbers;

(5) to provide documentation of non-programatic conservation trends for all respective customer classes;

(6) to provide documentation in support of all assumptions regarding the relative usage factors in a normal year and a design year, based on experience in three or more colder-than-normal (design or near-design) historical years;

(7) to develop disaggregated monthly usage factors for purposes of projecting sendout based on monthly usage patterns in at least the two most recent historical years;

(8) to provide documentation of the Company's design day forecast methodology commensurate with that which is to be filed with its normal year and design year forecast methodologies;

(9) to identify specific criteria which the Company uses to evaluate pipeline and supplemental supplies, as well as describing how each of these criteria was applied to each pipeline and supplemental supply identified and evaluated by the Company;

(10) to identify specific criteria which the Company uses to evaluate conservation programs, to describe how each of these criteria was applied to each conservation option identified and evaluated by the Company, and to demonstrate that an appropriate avoided cost study has been integrated into this process;

(11) to integrate the results of the avoided cost study into the Company's supply planning process;

(12) to quantify the savings of its existing and planned C&LM programs over the forecast period, and to incorporate these estimates into its base case resource plan and its analyses of adequacy for normal and design conditions; and

(13) to analyze the cost-effectiveness of all resource additions as part of total system cost in the context of a framework that analyzes the cost-effectiveness of resource additions, including C&LM, and weighs all resource additions on an equal footing.

The Siting Council further ORDERS Berkshire to file its next forecast on April 1, 1991.

Sue Munis Nord

Sue Munis Nord
Hearing Officer

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of February 9, 1990 by the members and designees present and voting. Voting for approval of the Tentative Decision as amended: Paul W. Gromer (Commissioner of Energy Resources); Barbara Kates-Garnick (for Mary Ann Walsh, Secretary of Consumer Affairs and Business Regulation); Joellen D'Esti (for Alden S. Raine, Secretary of Economic Affairs); Joseph Freeman (for John P. DeVillars, Secretary of Environmental Affairs); Joseph Joyce (Public Labor Member); Sarah Wald (Public Environmental Member); and Kenneth Astill (Public Engineering Member).

Paul W. Gromer
Chairperson

Dated this 9th day of February, 1990

TABLE 1

Berkshire Gas Company
Forecast of Firm Sendout by Customer Class

Normal Year
(mmcf)

Customer Class 1991-92	1987-88	
Residential Heating	2,213	2,515
Residential Non-heating	144	117
Commercial	1,602	1,906
Industrial	954	917
Company Use / Unaccounted	85	93
Total Sendout	4,998	5,548

Design Year
(mmcf)

Customer Class 1991-92	1987-88	
Residential Heating	2,302	2,616
Residential Non-heating	144	117
Commercial	1,658	1,971
Industrial	954	917
Company Use / Unaccounted	90	98
Total Sendout	5,148	5,719

Source: Exh. HO-1, Tab 2, Tables G-1 through G-5

TABLE 3

Berkshire Gas Company
Comparison of Resources and Requirements
Design Day (mmcf)

REQUIREMENTS	1989-90	1990-91	1991-92
Firm sendout	41.7	43.3	44.9
RESOURCES			
Tennessee CD-6	20.3	25.4[a]	25.4
Boundary	1.0	1.0	1.0
Storage Return	4.8	4.8	4.8
LNG Purchases	6.0	6.0	6.0
Propane from Storage	13.8	13.8	13.8
TOTAL	45.9	51.0	51.0

Notes:

a. NOREX volumes available.

Source: Exh. HO-R-12

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 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 services 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 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. (See. 5, Chapter 25, G.L. Ter. Ed., as most recently amended by Chapter 485 of the Acts of 1971).

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 First Supplement to their Joint Third Long-Range Forecast of Gas Requirements and Resources

EFSC 88-25

FINAL DECISION

Frank P. Pozniak
Hearing Officer
February 9, 1990

On the Decision:

Pamela M. Chan
Robert M. Graham

APPEARANCES:

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Petitioner

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Petitioner

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The Siting Council hereby APPROVES the sendout forecast and supply plan filed by the Boston Gas Company for the five years from 1988-89 through 1992-93.

I. INTRODUCTION

A. Background

Boston Gas Company ("Boston Gas" or "Company"), the largest local gas distribution company ("LDC") in the Commonwealth, serves the City of Boston and 73 other eastern and central Massachusetts communities (Exh. BGC-1, p. i).[1] In the split-year 1987-1988,[2] the Company had an average of 496,141 on-system firm service cutomers, consisting of 265,117 residential heating customers, 193,457 residential non-heating customers, 34,937 commercial customers, and 2,630 industrial customers (Exh. HO-RR-17, Tables G-1 through G-5). Boston Gas also makes firm sales to off-system customers[3] and sells gas to interruptible customers (id.).

Boston Gas's forecasts of sendout by customer class are summarized in Table 1. The Company projects an increase of total normalized firm sendout from 70,074 billion Btu ("BBtu")[4] in 1988-89 to 72,932 in 1992-93, or an increase of approximately 4 percent over the forecast period (Exh. HO-RR-17).

Boston Gas receives pipeline gas and underground storage return gas from the Tennessee Gas Pipeline Company

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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-sized company.

[2] A split-year runs from November 1 through October 31.

[3] Off-system customers purchase gas for resale outside Boston Gas' service territory.

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

("Tennessee") and from the Algonquin Gas Transmission Company ("Algonquin") (Exh. HO-SP-7).[5] Boston Gas has auxiliary liquefied natural gas ("LNG") facilities in Dorchester (Commercial Point facility), Lynn, and Salem, auxiliary propane facilities in Braintree, Danvers, Everett, Gloucester, Leominster, Norwood, Southbridge, Spencer, Reading, and Revere, and an auxiliary synthetic natural gas ("SNG") production facility in Everett (Exh. HO-SP-22A). Additionally, Boston Gas leases LNG storage and vaporization facilities from Distrigas of Massachusetts Corporation ("DOMAC") and LNG storage facilities from Algonquin (id.; Exh. HO-SP-22).

In the most recent decision regarding Boston Gas (Boston Gas Company, 16 DOMSC 173 (1987) ("1987 Boston Gas Decision"), the Energy Facilities Siting Council ("Siting Council" or "EFSC") rejected the Company's sendout forecast and supply plan. In addition, the Siting Council required the Company to comply with 10 orders from that decision. 1987 Boston Gas Decision, 16 DOMSC at 270-271.

B. Procedural History

On June 30, 1988, Boston Gas and Massachusetts LNG, Inc. ("Mass. LNG") filed their first annual supplement to the joint third long range forecast for the split years 1988-89 through 1992-1993.[6] On August 8, 1988, the Hearing Officer issued a Notice of Adjudication and directed the Company to publish and post the Notice in accordance with 980 CMR 1.03(2). The Company confirmed notice and publication on September 12, 1988. DOMAC participated as an interested person in the proceeding.

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[5] Boston Gas sends gas to underground storage during the non-heating season and the gas is returned for sendout during the heating season.

[6] Mass. LNG is a subsidiary of Boston Gas and holds long-term leases on the LNG storage facilities in Lynn and Salem (Exhs. BGC-1, p. i, HO-SP-22A). Mass. LNG makes no wholesale or retail sales of gas (Exh. BGC-1, p. i). The Siting Council's discussion of LNG facilities will refer to Boston Gas but apply to Mass. LNG where appropriate.

On April 21, 1989, the Company filed a motion for protective order requesting that the Siting Council grant protective treatment to certain portions of a report prepared by Arthur D. Little, Inc. ("ADL") for the Company and submitted in response to an information request of the Siting Council staff (Exh. HO-SF-56). The Hearing Officer granted this motion (Tr. 2, pp. 3-4). The Hearing Officer also granted a request for protective treatment of an internal cogeneration report prepared by the Company (Exh. HO-RR-8D; Tr. 4, p. 4).

The Siting Council conducted six days of evidentiary hearings during the proceeding. Boston Gas presented seven witnesses: Anthony DiGiovanni, Senior Vice President of Operations for the Company, who testified regarding gas supply planning; John J. Gilfeather, Planning and Design Engineer for the Company, who testified regarding distribution system planning; Kenneth J. Heaghney, Lead Consultant at Energy Management Associates, Inc. ("EMA"), who testified regarding the Company's methodology for weather normalizing sendout data; William R. Luthern, Vice President of Gas Supply and Production for the Company, who testified regarding updated forecast information and various supply matters; Carl P. Martinello, Manager of LNG and SNG Operations for the Company, who testified regarding the Company's LNG liquefaction facilities; Jane P. Michalek, Manager of Gas Supply Planning for the Company, who testified regarding the determination of supply needs, reasonableness of planning standards, and compliance with concerns identified in the 1987 Boston Gas Decision; and Gregory O. Tomlinson, Director of Market and Business Analysis for the Company, who testified regarding the sendout forecast and supply cost issues.

The Hearing Officer entered 218 exhibits into the record, largely composed of responses to information and record requests, including 22 responses to supplemental information requests of the Siting Council staff which were moved into evidence after the close of hearings. Boston Gas entered 81 exhibits into the record. On July 21, 1989, the Company filed its brief.

II. ANALYSIS OF THE SENDOUT FORECAST

A. Standard of Review

The Siting Council is directed by G.L. c. 164, sec. 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. Bay State Gas Company, EFSC 88-13, p. 5 (1989) ("1989 Bay State Decision"); Fitchburg Gas and Electric Light Company, EFSC 86-11(A), p. 4 (1989) ("1989 Fitchburg Decision"); Berkshire Gas Company, 16 DOMSC 53, 56 (1987) ("1987 Berkshire Decision"); 1987 Boston Gas Decision, 16 DOMSC at 179.

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. 1989 Bay State Decision, EFSC 88-13, p. 5; 1989 Fitchburg Decision, EFSC 86-11(A), p. 4; Commonwealth Gas Company, 17 DOMSC 71, 77-78 (1988) ("1988 ComGas Decision"); 1987 Berkshire Decision, 16 DOMSC at 55-56; 1987 Boston Gas Decision, 16 DOMSC at 179; Holyoke Gas and Electric Light Department, 15 DOMSC 1, 6 (1986) ("1986 Holyoke Decision"); Westfield Gas and Electric Light Department, 15 DOMSC 67, 72 (1986) ("1986 Westfield Decision").

B. Previous Sendout Forecast Review

In its previous decision, the Siting Council rejected Boston Gas's sendout forecast. 1987 Boston Gas Decision, 16 DOMSC at 177, 179-212. In addition, the Siting Council ordered Boston Gas to include in its next forecast filing:

> (1) the comprehensive report (i.e., the report originally required as part of the Company's September 1, 1987 filing) required in Condition Three of the Siting Council's decision in Boston Gas Company, EFSC 84-25 [16 DOMSC 1], (1986) ("1986 Boston Gas Decision").[7] Id., at 266, 271.

The Siting Council's rejection of the Company's sendout forecast in the previous decision was based in part on concerns related to the Company's weather data, methodologies for developing design planning standards, and assumptions included in the Company's interim forecasting model and regression equations. The specifics of these concerns and the Company's response are outlined more fully in the Siting Council's review of the Company's current weather data, planning standards and forecasting methodologies below.

Boston Gas's compliance with Order One is discussed in Section II.D.1, 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

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[7] As part of Condition Three of the 1986 Boston Gas Decision, the Siting Council required the Company to conduct a survey of comparable gas distribution companies (at least five) in other parts of the country to ascertain how other companies have addressed the same forecasting issues and how Boston Gas might modify its forecasting process to develop a more appropriate and reliable forecast. 1986 Boston Gas Decision, 16 DOMSC at 49. The Siting Council also required that the results of the study be used as reference for evaluating the Company's own assumptions, data, and methodology, and that upon completion of the evaluation, a report be prepared for the Siting Council summarizing the results and either confirming the appropriateness and reliability of each assumption, parameter, and judgment or recommending changes or modifications to the present forecasting methodology along with a plan for implementing those changes. Id.

Siting Council is required to review long-range forecasts of gas companies (see G.L. c. 164, secs. 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 upon which a company's planning standards are based. The second element of our 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 a 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 the last decision, the Siting Council found that the Company's weather analysis was deficient for failing to adequately consider the use of effective degree days ("EDD") as a method for improving sendout correlation with weather. 1987 Boston Gas Decision, 16 DOMSC at 185. In addition, the Siting Council found that the Company failed: (1) to adequately analyze the effects of moving the location of the Boston weather station from downtown Boston to Logan Airport; and (2) to establish that its planning standards based on these data are valid. Id., at 187. Finally, the Siting Council found that the Company failed to adequately maintain its normal and design year degree day ("DD") planning levels by updating the weather database. Id.

In this proceeding, the Company presented its weather data and supporting analyses (Exhs. BGC-4, pp. 4-5, BGC-5, BGC-8, BGC-9). The Company stated that it conducted a comprehensive review of its weather data and related planning standards in response to Siting Council concerns, and employed EMA to analyze specific aspects of its weather data (Exhs. BGC-4, p. 5, BGC-9, BGC-58, p. 9). Based on its review and the EMA analysis, the Company asserted that it has addressed the Siting Council's concerns and established the appropriateness and reliability of its weather data (Boston Gas Brief, p. 5).

Boston Gas indicated that it continues to use DD to correlate sendout data with weather data (Exh. BGC-4, p. 3). The Company stated however, that it evaluated the use of EDD instead of DD as a means of improving its long-range forecasting ability (id., p. 2; Exh. HO-1, p. 2). The Company presented studies of the correlation between wind speed and sendout, the correlation between DD and EDD, and compared the correlation between DD and sendout to the correlation between EDD and sendout (Exhs. BGC-5, BGC-6, HO-SF-2). The Company asserted that "[t]hese results indicate no statistical difference in the ability of degree days and effective degree days to predict daily sendout" (Boston Gas Brief, p. 9).

The Company's witness, Dr. Heaghney, reviewed and verified the Company's analysis and conclusions and stated that "degree days and effective degree days essentially do an equal job of modeling sendout" (Tr. 1, p. 69). Dr. Heaghney also stated that "there is no compelling reason for Boston Gas to change its long range planning methods to incorporate effective degree days in place of degree days" (Exh. BGC-4, p. 3). The Company's witness, Ms. Michalek, stated, however, that the Company will continue to review the relationship between sendout and EDD relative to the relationship between sendout and DD (Tr. 1, p. 91).

In the sendout forecast reviewed by the Siting Council in the 1987 Boston Gas Decision, the Company used a weather database extending from 1923 to 1973 which consisted of weather recorded by the National Weather Service in downtown Boston from 1923 through to 1935, and at Logan Airport from 1936 to 1973. See: 1987 Boston Gas Decision, 16 DOMSC at 183, 185-187. In that case, the Siting Council determined that fewer DD had been recorded in the period since 1936 than in the period prior to 1936. Id., at 185-187.

The Company engaged EMA to address the Siting Council's concern related to the possible impact of the change in location of weather stations on the accuracy of the weather data, and to the concern relating to updating the weather database as well (Exhs. BGC-4, BGC-9). The Company stated that EMA addressed this latter concern by updating the Company's database to include the years 1920-1985 (Exhs. BGC-4, p. 6, BGC-9, Executive Summary, p. 1, Sec. 2). The Company indicated that it intends to continue to update this weather database to include data from 1920 to the present (Exh. HO-SF-11).

The Company stated that EMA analyzed the weather database in an attempt to explain the difference in DD levels (Exhs. BGC-4, pp. 4-5, BGC-9, Sec. 2). The Company stated that EMA analyzed whether the difference was caused by: (1) a significant warming trend in weather patterns; (2) a shift in the weather station from downtown Boston to Logan Airport; and (3) a change in the way DD have been calculated over time (Exhs. BGC-4, p. 6, BGC-9, Executive Summary, p. 1). The Company asserted that the results of the EMA study show that a change in the method of calculating DD resulted in the apparent shift in the weather data (Exhs. BGC-4, p. 5, BGC-9, Sec. 2). EMA determined that in 1948, the National Oceanographic and Atmospheric Administration ("NOAA") changed its method of rounding average temperatures (id.). EMA indicated that prior to 1948, average temperatures were rounded up if the whole number portion was odd, and rounded down if the whole number was even (id.). EMA indicated that after 1948, average temperatures always were rounded up (id.). As a result, EMA determined that on an annual basis, this process would raise calculated average temperatures and reduce the calculated DD compared to the method of calculating DD before 1948 (Exhs. BGC-4, p. 6, BGC-9, Sec. 2).[8] EMA stated that

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[8] The Company stated that its own study of its weather data also showed that the method of rounding was the reason for the annual reduction in DD (Exh. BGC-4, p. 6).

recalculating the daily DD data resulted in a consistent database which shows that there is no statistical evidence of a warming trend in annual DD (id.).

The Company also indicated that EMA analyzed the weather data using an ordinary least squares regression to determine if a shift in the measuring site or time trend explained variations in annual DD (Exhs. BGC-4, p. 6, BGC-9, Sec. 3). EMA concluded that neither variable was significant in explaining variations in annual DD (id.). EMA also used a goodness of fit test to determine that annual DD from the Company's data could be characterized by a normal distribution (Exhs. BGC-4, pp. 6-7, BGC-9, Sec. 2). Dr. Heaghney stated that EMA found that the weather data that Boston Gas now uses which is based for the entire period from 1920 to 1985 on the current method of rounding, is consistent and shows no evidence of warming (Tr. 1, p. 75; Exhs. BGC-4, pp. 6-7, BGC-9, Sec. 2).

The Company asserted that its weather database is appropriate and reliable for use in developing its planning standards for its entire service territory (Boston Gas Brief, p. 6). The Company also asserted that Logan Airport weather data is the "most representative single temperature source for its service territory" (Exh. HO-SF-10). The Company stated, however, that it had not performed studies of variations in temperatures across its service territory with the exception of a 1982 study of temperatures from the Blue Hills weather station, which the Company updated for this proceeding (Exhs. HO-SF-10, HO-SF-48). The Company noted that the location of the Blue Hills weather station at an elevation of 650 feet above sea level led Boston Gas to believe that Blue Hills data was not representative of the majority of Boston Gas' service territory (Exh. HO-SF-10). However, the Company stated that a high correlation exists between temperatures at Logan Airport and Blue Hills (id.; Tr. 4, p. 92). Ms. Michalek stated that while a significant temperature difference may exist across its service territory, the correlation of Company-wide sendout to Logan Airport temperature is consistent throughout the Company's service territory, and therefore, the

Company is satisified that Logan Airport DD data is appropriate for use in developing planning standards and forecasting sendout (Tr. 4, pp. 118-120). Finally, the Company stated that the integration of the Company's distribution system enables the Company to appropriately plan for its entire service territory based on one planning standard (id., p. 118).

b. Analysis

In the previous decision, the Siting Council criticized the Company for failing to adequately consider the use of EDD as a method for improving sendout correlation with weather. 1987 Boston Gas Decision, 16 DOMSC at 185. In this proceeding, the Company responded to that criticism by presenting studies analyzing the correlation of sendout to DD and EDD. The Company also had EMA review these studies and presented the results of EMA's analysis. Thus, the Company has presented sufficient documentation and supporting analyses in this proceeding to establish that the use of EDD rather than DD currently would not provide a significant improvement in the Company's ability to forecast sendout.

Nevertheless, the Siting Council notes that the Company's analyses show a consistent, although minor, improvement in correlation with sendout when EDD are used. In the past, the Siting Council has ordered companies of Boston Gas' size and resources to pursue forecasting enhancements aggressively. See: 1986 Gas Generic Order, 14 DOMSC at 104. In past decisions regarding the sendout forecasts of large gas companies, the Siting Council has found that one such enhancement is the use of EED as the primary weather indicator. See: 1988 ComGas Decision, 17 DOMSC at 80-81; Bay State Gas Company, 16 DOMSC 283, 299-300 (1987). In fact, recently, one large gas company in the Commonwealth has begun to use EDD as the primary weather indicator. See: 1989 Bay State Decision, EFSC 88-13, p. 8. Accordingly, the Siting Council directs the Company to continue to monitor correlation relationships between sendout and DD and EDD, and to incorporate any significant changes in its weather database and forecasting methodologies.

The Company has addressed the majority of the Siting Council's concerns in the previous decision relating to the appropriateness and reliability of the Company's weather database. While the Company did not directly address the issue of the apparent decline in occurrences of extremely cold days, the Siting Council finds that the Company has established that its weather data base, updated and revised to account for inconsistencies in the calculation of daily DDs, represents a consistent and reliable data base for planning purposes.

However, the Company has not established that Logan Airport weather data is truly "the most representative single temperature source for [Boston Gas'] service territory." The Company's arguments relating to the correlation between temperatures at Logan Airport and Blue Hills are relevant to the correlation between DD and sendout on an annual basis for the service territory as a whole. The Siting Council notes, however, that in developing planning standards, the specific daily DD levels as well as the pattern of daily DD are important.

In a previous case, the Siting Council has accepted distribution system flexibility as justification for aggregate forecasting across diverse geographic areas. 1989 Bay State Decision, EFSC 88-13, p. 29. However, the Siting Council also consistently has held that weather data must be specific to the geographic area under consideration. 1989 Fitchburg Decision, EFSC 86-11(A), pp. 7-8; 1988 ComGas Decision, 17 DOMSC at 83-86. It is conceivable that a strong correlation could be shown to exist between sendout for Boston Gas' service territory and weather data from New York City, but use of such distant weather data in the development of planning standards clearly would be inappropriate. The reliability of such standards is impacted directly by the appropriateness of the weather data for a specific geographic area.

The Siting Council concurs that the Blue Hills data is not likely to be representative of the Company's entire service territory due to its elevation. The Siting Council notes, however, that ocean effects present at Logan Airport may render Logan Airport DD data similarly unrepresentative of the Company's service territory as a whole. Therefore, the Siting Council ORDERS Boston Gas to include in its next forecast filing 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 Airport 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.

Nonetheless, for the purposes of this review, the Siting Council finds that the Company has established that it has a reviewable and minimally appropriate and reliable weather database for use in the development of its planning standards.

2. Normal Year Standard

In the 1987 Boston Gas Decision, the Siting Council found that the Company's methodology for determining its normal year planning standard -- averaging the number of degree days that have occurred during its selected range of weather data, allocating DD to each month based on historical occurrence, and randomly distributing cold and warm periods within each month -- was reviewable and appropriate. 1987 Boston Gas Decision, 16 DOMSC at 188. The Siting Council also found, however, that the standard was unreliable due to concerns related to the Company's weather database as discussed above (id.).

In the instant proceeding, the Company presented a new normal year standard of 5,695 DD, which had been revised to reflect the average number of annual degree days over the updated range of weather data from 1920 to 1985 (Exhs. BGC-4, p. 7, BGC-9, Sec. 3). In addition, the Company indicated that it had reallocated monthly DD to correspond to the new annual standard based on monthly averages and daily DD frequency distributions recommended by EMA (Exhs. BGC-4, p. 7, BGC-9, Sec. 4, p. 16).

The Siting Council finds that the Company has established that its methodology for determining the normal year planning standard is reviewable and appropriate. The Siting Council notes that the Company has addressed a majority of the concerns related to the weather data upon which the normal standard is based (see Section II.C.1, above). The Siting Council expects that the Company will continue to review its normal year standard and DD distribution as appropriate based on updated weather data, and on the results of the weather data study ordered in Section II.C.1.b, above. Accordingly, the Siting Council finds that the Company's normal year standard is minimally reliable.

3. <u>Design Year Standard</u>

The Siting Council, in the <u>1986 Gas Generic Order</u>, 14 DOMSC at 97, placed gas companies on notice 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 encountered." 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 recur, and to the effect of the design standard on the reliability of the company's forecast and the cost of its supply plan. <u>Id.</u>, 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. <u>1989 Bay State Decision</u>, EFSC 88-13, p. 10; <u>1988 ComGas Decision</u>, 17 DOMSC at 87; <u>1987 Boston Gas Decision</u>, 16 DOMSC at 188-190.

In the 1987 Boston Gas decision, the Siting Council found that the Company "failed to establish that it manages the level of reliability maintained by" its design day standard. <u>1987 Boston Gas Decision</u>, 16 DOMSC at 189. Further, the Siting Council found that the Company "failed to adequately consider cost/reliability tradeoffs in setting its design year planning standard." <u>Id.</u>, p. 190.

a. Description

In the instant proceeding, the Company has maintained its historic design year standard of 6,300 DD (Exhs. BGC-1, Sec. 1, Table DD, BGC-4, p. 7, BGC-9, BGC-58, p. 10, BGC-75, p. 16). The Company asserted that this standard "has undergone extensive review since the issuance of the Siting Council's 1987 Boston Gas Decision to determine whether it continues to be appropriate" (Boston Gas Brief, p. 7). The Company also noted that while the design year standard was not adjusted as a result of the review, the Company did reallocate degree days within the design year in accordance with the recommendations of EMA (Exhs. BGC-4, p. 7, BGC-9, Sec. 4, pp. 16-17, BGC-58, p. 10).[9] In regard to the reliability level associated with the design year standard, the Company presented an analysis which indicates that, on a split-year basis, there is a probability of one in 15 that a 6,300 DD year will occur (Exhs. HO-SF-12, BGC-4, p. 7). The Company stated that it places more emphasis on design weather in the winter period due to increased costs and the limited availability of gas supply options to serve customer demand (Exh. HO-SF-13). While the Company did not specify a level of reliability which it considered to be minimally acceptable, the Company stated that the 4,962 DD associated with the five coldest months in its design year have a probability of occurrence of approximately one-in-eight, and that each of the three coldest months in the design year -- December, January and February -- has a probability of occurrence of approximately one-in-six (Exhs. HO-SF-50, BGC-9, Sec. 4, pp. 17, 26, BGC-10).

The Company indicated that in determining that 6,300 DD remained an appropriate design year planning standard, it considered the possibility of weather changes, the composition

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9/ EMA developed a design year daily DD pattern for the Company's 6,300 DD design year by increasing the DD for each day of the revised normal year by 10.6 percent, adjusting for rounding differences, and incorporating a 73 DD peak day (Exh. BGC-9, Sec. 4, p. 16).

of the Company's gas supply portfolio, and the costs associated with maintaining the standard (Exhs. HO-SF-14, HO-SF-49, HO-SF-50, BGC-75, p. 17; Tr. 1, pp. 101-106).

In regard to weather changes, the Company noted that its weather data analysis indicated no trends in weather patterns which would suggest a need for a change in standards (Exh. HO-SF-14). See Section II.C.1, above.

In regard to the impact of the Company's gas supply portfolio on the appropriateness of its design year planning standard, the Company stated that the significant factors which should be considered are: "(1) the extent to which pipeline supplies require peak shaving; (2) the availability of peak shaving resources; (3) the displacement, conversion, or supply reduction options; and (4) the market opportunities which may exist" at a given time (Exh. HO-SF-49). Ms. Michalek stated that "an assessment of costs [is] necessary each and every time there is a change in one of these major factors" (Tr. 1, p. 105). Ms. Michalek also stated, however, that while "over the past 15 or so years" there has been a significant drop-off in the reliability of supplemental supplies, the Company determined that its design planning standards remained appropriate as a result of the increased percentage of pipeline supplies in its portfolio (id., pp. 105-106).

In regard to the cost impact of maintaining the Company's design year standard, the Company presented an analysis which compared the gas and non-gas costs associated with its 6,300 DD standard to the costs at five other DD levels -- 6,000 DD, 6,100 DD, 6,200 DD, 6,400 DD and 6,500 DD (Exhs. BGC-75, p. 17, BGC-80; Tr. 6, pp. 35-44). This analysis, which used 1987-1988 as the base year, showed that a reduction of design year DD to 6,000 DD would result in an annual $1.9 million cost decrease relative to a 6,300 DD, and an increase in design year DD to 6,500 DD would result in an annual $2.5 million cost increase (Exhs. BGC-75, p. 17, BGC-80; Tr. 6, pp. 39-40). The Company's witness, Mr. Luthern, noted that a design year of 6,000 DD would have a probability of occurrence of one-in-five and stated that, in the Company's judgment those "increased risks far outweigh the potential savings" (Exh. BGC-75, p. 18; Tr. 6, p. 40). In support of this statement, Mr. Luthern noted that in the winter of 1980-81 the Company incurred $46.5 million dollars in extraordinary gas costs due mainly to colder than design weather during the month of January and shipment difficulties with LNG supplies (Exh. BGC-75, p. 19). In addition, Mr. Luthern described the costs associated with restoring service to customers in the event of a loss of service (id., pp. 19-20). In sum, Mr. Luthern stated that "these are not the sort of risks the Company wants to run a 1-in-5 chance of incurring," and that the 6,300 DD design year "reflects a level of risk -- 1-in-15 -- that is proper" (id., p. 20).

b. Analysis

The Siting Council acknowledged in its last Boston Gas decision that while design planning standards are in some manner based on judgment, such judgment must be based upon appropriate analyses of the reliability and costs associated with various standards. 1987 Boston Gas Decision, 16 DOMSC at 189-190. In this proceeding, the Company has made significant progress in its effort to document and justify its selection of a design year standard of 6,300 DD. Here, the Company has analyzed the level of reliability achieved by its standard, identified appropriate factors for consideration in determining an acceptable level of reliability, and presented a detailed and comprehensive costs analysis of the impacts of differing design year standards. Further, the Company has indicated that it regularly reassesses the factors which contribute to its decision regarding its design year planning standard. Therefore, Siting Council finds that, for the purposes of this review, the Company has established that its methodology for determining its design year standard is reviewable and appropriate.

The Siting Council expects that, as with the normal year standard, the Company will continue to review its design year standard and DD distribution as appropriate based on updated weather data, and on the results of the weather data study ordered in Section II.C.1.b, above. Accordingly, the Siting

Council finds that the Company's design year standard is minimally reliable.

The Siting Council notes however, that the Company's documentation and analysis in support of the continued use of the 6,300 DD design year standard seem to amount to a situation where DD determines reliability rather than reliability determining DD -- a significant concern in the Siting Council's last decision. See: 1987 Boston Gas Decision, 16 DOMSC at 189-190. While the Company has established that it has considered the tradeoffs between cost and reliability associated with its design year standard, and has indicated that a 1-in-15 year risk of incurring these costs is acceptable, the Company has failed to clearly establish that a 1-in-15 year probability of occurrence is appropriate based on the particulars of the Company's capacity and supply portfolio. Large gas companies such as Boston Gas should be able to provide a sophisticated analysis of the appropriate level of reliability for design planning based on sendout mix, baseload and supplemental supply mix, and distribution system flexibility. Here, while the Company stated that it considers such factors important in setting a design planning standard, the Company stopped short of providing an analysis supporting its assertions that a 1-in-15 occurence probability is in fact the appropriate level of reliability based on these factors. In addition, the Company appeared to contradict itself by stating that design weather during the winter periods is most critical, while accepting probabilities of occurrence of as low as one-in-six for individual winter months and one-in-eight for design winters as a whole. Therefore, the Siting Council ORDERS the Company in its next forecast filing 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.

Nonetheless, the Siting Council's criticisms of the Company's reliability analysis are offset here by the significant levels of documentation and analysis the Company has presented to justify its design year DD standard. The Siting Council notes that the cost/reliability tradeoff analysis presented by Boston Gas represents the first such comprehensive and detailed analysis the Siting Council has received in its review of gas company sendout forecasts. Clearly, this type of analysis is appropriate for a company the size of Boston Gas.

4. Design Day Standard

The Siting Council's Decision in the 1986 Gas Generic Order, 14 DOMSC at 97, regarding the development of design criteria applies to both design year and design day standards. 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 1987 Boston Gas Decision, the Siting Council found that the Company failed to establish "that it adequately considered the level of reliability set by its design day planning standard, or the cost/reliability tradeoffs necessary to maintain that planning standard." 1987 Boston Gas Decision, 16 DOMSC at 191.

a. Description

As with its design year standard, Boston Gas has maintained its historic design day standard of 73 DD in this proceeding (Exhs. BGC-1, Sec. 1, Table DD, BGC-58, p. 9). The Company stated that this standard represents the coldest day actually experienced in the Company's weather database, which occurred on February 9, 1934 (Exh. BGC-58, p. 9).[10] The

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[10] As part of its development of a consistent weather database for Boston Gas, EMA noted that once the current method of rounding average temperatures is used, the coldest day ever recorded becomes 72 DD as opposed to 73 DD (Exh. BGC-9, p. 28). The Company stated that, at such extremes of temperatures, it "does not consider such differences in degree days as significant" (Exh. HO-SF-16).

Company stated that it determined that 73 DD remained an appropriate design day standard for the Company based on the results of the EMA weather study and consideration of several factors including: (1) the probability of occurrence of the standard; (2) the Company's reserve margin to meet design day sendout; (3) the reliability of the sendout forecast; and (4) the reliability of the supply mix in general (id.). In addition, the Company noted that EMA reviewed the 73 DD standard and indicated that it was consistent with the Company's "position at the end of the pipelines, heavy dependence on peak shaving, and large temperature sensitive load" (Exh. BGC-64, p. 49; Boston Gas Brief, pp. 6-7).[11]

The Company asserted that the lack of apparent trends in its weather data implies that if 73 DD occurred once, it can occur again, and noted that the probability of a 73 DD occurring in one of the three coldest winter months is one-in-70 (Exhs. BGC-9, Sec. 5, p. 29, HO-SF-15, HO-SF-17, HO-SF-18, HO-SF-52, HO-SF-53). The Company stated that it is appropriate to have a significantly lower probability of occurrence for its design day standard than for its design year or design winter standards because "the Company holds more supply options in reacting to a design year occurrence than it does for a design day" (Exh. HO-SF-15). The Company noted that the lead time necessary to secure additional supplies and, consequently, supply flexibility, are "at a minimum in the case of a design day" (id.). In addition, the Company stated that it has little data related to customer usage patterns during periods of extreme weather, and noted that its current supply portfolio requires that approximately 50 percent of design day requirements be met with peak shaving resources.

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[11] In addition to the weather study, Boston Gas employed EMA to perform a separate study of the Company's forecasting methodologies as part of its response to Order One from the 1987 Boston Gas Decision (see Section II.B, above, for a description of this Order). For further discussion of this study, see Section II.D.1, below.

In regard to the costs associated with maintaining its design day standard, the Company presented an analysis of the costs associated with a range of daily DD levels -- 65 DD, 70 DD, 72 DD, 73 DD, and 80 DD (Exh. HO-SF-54).[12] This analysis assumes propane as the variable supply associated with the different DD levels, and therefore presents changes in commodity costs resulting from changes in propane use (id.). The Company stated that alterations in its design day capacity would not be necessary at any of the DD levels evaluated, and therefore changes in demand or capacity charges were not included in the analysis (id.). The analysis shows that, in 1988-89, a 65 DD design day would result in a $320,000 decrease relative to a 73 DD design day, while in 1992-93, the last year of the forecast period, a 65 DD would result in a $137,000 decrease relative to a 73 DD design day. The analysis also shows that, in 1988-89, an 80 DD design day would result in a $280,000 increase relative to a 73 DD design day, while in 1992-93, the last year of the forecast period, an 80 DD would result in a $177,000 increase relative to a 73 DD design day.

While the Company did not include capacity costs in this analysis, the Company stated that "the cost per Mcf of incremental capacity on the peak day is relatively inexpensive" (Exh. BGC-58, p. 9). In support of this assertion, the Company referred to the addition in 1987 of a 65.0 MMcf vaporizer at the Company's Commercial Point facility, noting that over the 20-year life of the vaporizer the cost averages out to $.00231 per mcf (id., p. 10; Exhs. HO-SF-19, HO-SF-20). Ms. Michalek stated that this is a "small cost for substantially more reliability" (Exh. BGC-58, p. 10). The Company noted that this capacity increased the reserve margin of the Company's supply portfolio for meeting design day sendout, and allowed the Company to increase its standby vaporization capacity, thereby

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[12] The Company identified the probability of occurrence associated with these DD levels as follows: for 65 DD, 1-in-8; for 70 DD, 1-in-30; for 72 DD, 1-in-53; for 73 DD, 1-in-70; and for 80 DD, 1-in-529 (Exh. HO-RR-21).

adding increased protection in the event of a supply or production failure coincident with a design day occurrence (Exh. HO-SF-20). The Company stated that "if all other conditions remain static" the increased capacity would allow the Company to accommodate a design day level of 80 DD (id.).

b. Analysis

The Siting Council acknowledged in its last Boston Gas decision that while design planning standards are in some manner based on judgment, such judgment must be based upon appropriate analyses of the reliability and costs associated with various standards. 1987 Boston Gas Decision, 16 DOMSC at 189-191. In this proceeding, the Company has made significant progress in its effort to document and justify its selection of a design day standard of 73 DD. Here, the Company has identified the level of reliability achieved by its standard, has discussed appropriate factors for consideration in determining an acceptable level of reliability, and has presented a detailed and comprehensive cost analysis of the impacts of a range of design day standards.

Therefore, the Siting Council finds that, for the purposes of this review, the Company has established that its methodology for determining its design day standard is reviewable and appropriate. The Siting Council expects that, as with the normal year and design year standards, the Company will review its design day standard as appropriate based on updated weather data, and based on the results of the weather data study ordered in Section II.C.1.b, above. Accordingly, the Siting Council finds that the Company's design day standard is minimally reliable.

However, while the Company has completed a detailed cost analysis in support of its selected design day standard, the Company has not addressed the reliability of its standard with the same level of sophistication. In support of its 73 DD standard, the Company seems to place considerable emphasis on the notion that if a DD level occurred once, it can occur again, as well as on a variety of other reliability factors --

the Company's location at the end of the domestic pipeline system, its heavy dependence on a high percentage of peak shaving resources to meet planned DD sendout, and the reserve margin and reliability level of its resource mix in general. In fact, the Company's reliability analyses could be interpreted as support for several different design day standards. The Company indicated that its actual coldest day level when considering the current method of rounding is 72 DD (with an associated probability of occurrence of 1-in-53). Further, the Company noted that it recently added a vaporizer at its Commercial Point facility which provided substantially increased standby capacity and reserve margin and in fact would enable the Company to meet an 80 DD day (with a probability of occurrence of 1-in-529).

Despite the fact that the Company identified reliability factors which impact its choice of an appropriate design day standard, the Company failed to establish that it evaluated its standard as a result of these factors and instead, continues to assert that the same standard it has used for years remains appropriate. The wide range of occurrence probabilities reflected here raises the question whether the Company in fact, manages the reliability level set by its design day standard, or instead makes resource decisions based on some other factor(s) but continues to apply its historic design day standard for reasons not directly related to reliability factors. Accordingly, Siting Council ORDERS the Company in its next forecast filing 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.

5. Conclusions on Planning Standards

In previous sections of this decision, the Siting Council has found that: (1) the Company has a reviewable and minimally appropriate and reliable weather database for use in the development of its planning standards; (2) the Company has a reviewable, appropriate and and minimally reliable normal year standard; (3) the Company has a reviewable, appropriate and minimally 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 the Company's planning standards are reviewable, appropriate and reliable.

D. Forecast Methodologies

The Company stated that as a result of new supply options, "the Company's sendout requirements are increasingly becoming a function of the demand for gas" (Exh. HO-SF-21). As a result of this situation, the Company stated that it began developing a demand based forecasting methodology in 1985 (id.). The Company presented its new methodology to the Siting Council for the first time in its last forecast proceeding (Exh. BGC-21, pp. 3-4). In its last decision, the Siting Council reviewed the significant elements of the methodology which are: (1) use of a market simulation model to identify market growth and development of marketing policies based on the market potential identified by the model; and (2) analysis of existing sendout through use of a multiple regression model. 1987 Boston Gas Decision, 16 DOMSC at 192-208. In that decision, the Siting Council found that these basic elements of the Company's new forecasting methodology represented an appropriate sendout forecasting methodology for Boston Gas. Id., p. 207. The Siting Council also found, however, that significant aspects of each of these elements were "not appropriately and/or reliably designed and executed." Id. In addition, the Siting Council ordered the Company to undertake an extensive review of its forecast methodology and supply planning process. Id., p. 270.

In the instant proceeding, the Company presented a more fully developed demand forecasting methodology incorporating the same principal elements of its previous methodology (Exh. BGC-1, Sec. 1, p. 2). The Company stated that its current methodology is the result of a review by the Company of both the methodology itself and the significant input factors (Exh. BGC-21, p. 6). The Company presented revised market simulation models for the Company's traditional markets -- small residential, apartment house, and commercial/industrial (id., pp. 21-28). The Company also included forecasts of the cogeneration and gas air conditioning markets developing in its service territory (id., pp. 29-31). The Siting Council reviews the Company's response to the previous order, the principal elements of the Company's forecasting methodology, and the resulting normal year, design year, and design day sendout forecasts below.

1. Compliance With Order One

In the 1986 Boston Gas Decision, 16 DOMSC at 49, the Siting Council ordered the Company to undertake an extensive review of its sendout forecast methodology and supply planning process. In the 1986 decision, the Company also was ordered to survey five comparable gas distribution companies to ascertain how other companies address issues similar to those faced by Boston Gas, so as to provide the Company with guidance in evaluating the foundation of its forecast methodology. Id. The Siting Council also ordered that upon completion of the evaluation, a comprehensive report be filed with the Siting Council in its 1987 filing. Id. In the 1987 Boston Gas Decision, 16 DOMSC at 270, the Company again was ordered to provide the report as part of the current forecast filing (Order One).

In response to Order One, the Company hired EMA to conduct a survey of five gas companies (Exh. BGC-58, pp. 8, 11-12). The Company presented the results of that survey in this proceeding (Exh. BGC-64). The Company stated that EMA reviewed the forecasting methodologies of Brooklyn

Union Gas Company, Southwestern Gas Corporation, Washington Gas Light Company, LaClede Gas Company, and People's Gas Light and Coke Company (Exh. BGC-58, p. 12). Ms. Michalek stated that these companies were chosen because of their similarities to Boston Gas including a "large proportion of firm load and constrained supply situation" (id.). The Company asserted that the results of the survey establish that the forecasting methods of Boston Gas are comparable to or exceed the methods of the other companies surveyed (id.; Boston Gas Brief, p. 10). Ms. Michalek stated that the Company will continue to review its methodology and make changes as appropriate (id.).

The Siting Council finds that the study performed by Boston Gas and EMA represents a reasonably comprehensive review of the Company's forecasting and supply planning methodologies relative to comparable gas companies. Accordingly, the Siting Council finds that the Company has complied with Order One of the last decision.

2. Market Simulation Model

In the 1987 Boston Gas Decision, 16 DOMSC at 203, the Siting Council reviewed the Company's interim market simulation model as part of the Company's new forecasting methodology. In that decision, the Siting Council noted that "end-use models, if implemented properly, can be effective methods for forecasting market demand," but found that the Company failed to establish that its interim model was an appropriate input to its sendout forecast methodology. Id., p. 204. In reaching this finding, the Siting Council noted that the Company's interim model "relied heavily on broad simplifying assumptions" to develop the forecast in that proceeding. Id., p. 203. The Siting Council also found in that decision that the Company's marketing policies based on market potential identified by the interim model did not "reliably predict gross load additions and net load gain." Id., p. 204.

In this proceeding, the Company presented the "first versions" of its individual demand forecasting models (Exh. BGC-21, p. 5). The Company stated that these models predict energy demand for both existing and new energy users in the Boston Gas service territory for the small residential, apartment house, and commercial/industrial sectors based upon explicit forecasts of employment and households (id., pp. 5-6; Exh. BGC-1, Sec. 1, p. 2). The Company stated that it first estimates energy demand for a base year for each sector (Exh. BGC-21, pp. 14-15).[13] The Company stated that base year demand is then input to the end-use models along with other data relating to price elasticity, impacts of equipment replacement and long-run conservation, fuel switching, attrition, and economic expansion (id.). The Company stated that since the 1987 Boston Gas decision, it had hired ADL to review and update the significant input parameters used in the models (Exhs. BGC-21, p. 6, HO-SF-56). In addition, the Company stated that it used data from "the most reliable data sources available" (Exhs. HO-SF-22, BGC-21, pp. 11-13).

The Company stated that it determines its market share of the predicted energy demand from new energy users by evaluating such factors as relative fuel prices, customer preference, historical market share, distribution system coverage, and environmental restrictions (Exhs. BGC-1, pp. 8-9, BGC-21, p. 6, 33, HO-SF-58). The Siting Council reviews the Company's forecasting assumptions and model development below.

a. Base Year Energy Demand

For the small residential sector, the Company stated that it estimated base year energy demand by customer class (heating customers, non-heating customers, and non-gas users), building type (single family or 2 to 4 family house), fuel (gas, oil, electric), and end-use (heating, cooking, etc.) (Exh. BGC-21, pp. 17-18). The Company estimated total households in its service territory for the base year based on 1980 U.S. Census data updated for new building permit and

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13/ The Company stated that it used 1986 as its base year for this forecast (Exh. BGC-21, p. 15).

demolition data, and estimated average energy use per household based on the Massachusetts average (id.; Exh. HO-SF-27; Tr. 2, pp. 45-48). The Company separated total energy into fuel type using Company data for gas sales, Boston Edison Company and Massachusetts Electric Company data for electric sales, and assuming the remainder to be oil sales (id.). To estimate base year energy demand by end-use, the Company estimated the distribution of various energy-using equipment by fuel type based on the Company's 1986 Appliance Saturation Survey and electric utility saturation survey data, and estimated average energy use per appliance based on Company and electric utility data (Exh. BGC-21, pp. 17-18).

For the apartment house sector, the Company stated that it estimated base year energy demand in the same manner as for the small residential sector with the exception that gas sales were allocated based on different applicable rates (id.; Tr. 2, pp. 48-50).

For the commercial/industrial sector, the Company stated that it estimated base year energy demand for 67 standard industrial classification ("SIC") codes (Exh. BGC-21, pp. 15-16). The Company estimated total energy demand for all fuels as the product of employment and average energy use per employee (id.). The Company used 1986 employment data for each SIC code from the Massachusetts Division of Employment Security ("MDES") (id.). The Company based average energy use per employee for the commercial sector on the Massachusetts average "scaled to reflect varying energy intensity by industry," and based average use per employee for the industrial sector on data from the 1981 U.S. Census Survey of Manufacturers (id.; Exhs. BGC-27, BGC-28, HO-SF-25, HO-RR-6; Tr. 2, pp. 29-34, 43-44). The Company then separated total energy demand by fuel and end-use in the same manner as for the small residential and apartment sectors (Exhs. BGC-21, pp. 15-16, HO-SF-26, HO-RR-6; Tr. 2, pp. 34-37, 43-44).

For the purposes of this review, the Siting Council finds that the Company's forecast of base year energy demand is reviewable, appropriate, and reliable.

b. Employment and Household Forecasts

The Company stated that it forecasts employment and households for seven geographic areas[14] in its service territory based on projections from outside consulting firms and state agencies which the Company adapts to its service territory (Exh. BGC-21, p. 19). Mr. Tomlinson stated that by generating its final forecasts for the seven regions rather than for specific cities and towns, the Company avoids the difficulties in accurately forecasting for specific cities and towns and maintains the relationship between growth in sendout requirements and distribution system requirements (Tr. 2, pp. 60-62).

In regard to its employment forecast, the Company stated that it projects total commercial employment and total industrial employment for each city and town to increase at the same rate as employment growth in the county of which it is a part (id.). The Company purchased forecasts of county level employment from Data Resources, Inc. ("DRI") and the National Planning Association ("NPA") (id.). The Company separated total commercial and industrial employment projections into the 67 SIC codes based on projections from the MDES (id., p. 20, Exhs. BGC-30, HO-SF-28; Tr. 2, pp. 53-55). The Company's employment forecast projects the rate of employment growth to drop relative to recent levels, but projects continued commercial/industrial expansion at a rate up to one percent annually (id.).

In regard to its household forecast, the Company stated that it forecasts households by building type based on

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[14] The Company identified the seven regions as Central Massachusetts, West suburban Boston, Boston, Southern suburban Boston, Mystic Valley, Lynn, and the North Shore (Exh. HO-SF-56, pp. II-2; Tr. 2, p. 51). Mr. Tomlinson noted that these regions were developed as part of the work done by ADL for Boston Gas in its 1985 report and are used consistently throughout all the Company's market simulation forecasts (Tr. 2, pp. 51-52). Mr. Tomlinson also stated that the breakdown of cities and towns into the seven regions was based on supply and system distribution considerations (id.).

population and household projections from DRI and NPA (Exh. BGC-21, p. 20; Tr. 2, pp. 62-65). As with the employment forecast, the Company projected households for each city and town to increase at the same rate as household growth in the county of which it is a part (id.). The Company separated new households into building types based on recent building permit activity in the seven geographic areas (Exhs. BGC-21, p. 20, BGC-33; Tr. 2, pp. 65-67). The Company's household forecast projects small residential households to increase at a rate of up to 0.9 percent annually throughout the forecast period, and projects apartment house growth to gradually decline from an annual rate of 3.8 percent in 1987 to a rate of 2.4 percent in 1993 (Exh. BGC-32).

For the purposes of this review, the Siting Council finds that the Company's forecasts of employment and households are reviewable, appropriate, and reliable.

c. Demand Forecasting Models

The Company's demand forecasting models project energy demand for both existing and new energy users as the product of an average energy use per household and number of households for the small residential and apartment house sectors, and the product of average energy use per employee and number of employees for the commercial/industrial sector (Exh. BGC-21, pp. 21-22, 24-28). For existing energy users, the models project energy use by adjusting base year energy demand for each sector for the impacts of short run price elasticity, stock replacement and permanent conservation, and fuel switching based primarily on recommendations made to the Company by ADL (id.; Exhs. BGC-35, HO-SF-29; Tr. 2, pp. 71-76). For existing energy users, the models project numbers of households and employees by adjusting existing numbers for attrition based on the employment and household forecasts (Exh. BGC-21, pp. 22, 24, 27; Tr. 2, pp. 77-81).

The Company stated that it assumes that as prices increase by 10 percent, average consumption will decline by two percent (Exh. BGC-21, pp. 21, 24, 27). This reflects the price elasticity factor of -0.2 recommended by ADL in its updated study (id.). In addition, the Company stated that for the small residential sector, it estimated stock replacement based on equipment age distributions from its 1986 residential saturation survey, and new equipment efficiencies based on ADL estimates and Massachusetts appliance efficiency standards (Exh. BGC-21, p. 27). The Company stated that it assumes fuel switching will only take place when equipment breaks down (id., pp. 22, 25, 27), and noted that for the apartment house and commercial/industrial sectors, switching potential is therefore limited to that portion of centrally-fired gas and oil boilers which retire each year[15] (id., pp. 22, 25).

In regard to new energy users, the models predict energy use based on new employment and new households from the employment and household forecasts, new average energy use per employee or household, and estimated fuel market share by end-use (Exh. BGC-21, pp. 22, 25, 28). The new average energy use per employee or household is based on base year average energy use, as adjusted for the impacts of new equipment efficiency and building shell improvements based on ADL estimates[16] (id., pp. 23, 25, 28). The Company stated that estimates of market share by end-use also are based primarily on ADL estimates for heating equipment systems, while, for non-heating end-uses, gas was assumed to maintain its current market share in all sectors (id., Exh. HO-SF-30). Mr. Tomlinson stated that this assumption was acceptable because the bulk of the Company's additions in load for each sector are

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[15] The Company stated that it assumed five percent of all existing boilers will retire each year (Exh. HO-SF-29). The Company developed estimates of the portion of this five percent which will switch fuels based in part on a life-cycle cost comparison of gas and oil (id.).

[16] The Company stated that ADL estimated that new commercial, industrial, and apartment house buildings will consume about 90 percent, 80 percent, and 75 percent of existing average energy consumption, respectively (Exh. BGC-21, pp. 23, 25).

from heating end-uses (Tr. 2, pp. 83-84). The Company also assumed that the market share for gas will increase in all sectors during the forecast period based on Company marketing programs targeted to non-heating customers (Exh. BGC-21, pp. 28-29).

For the purposes of this review, the Siting Council finds that the Company's forecasts of energy demand for existing and new energy users in the small residential, apartment house, and commercial/industrial sectors are reviewable, appropriate, and reliable.

d. Conclusions on Market Simulation Model

In previous sections of this decision, the Siting Council has found that, for the purposes of this review: (1) the Company's forecast of base year energy demand is reviewable, appropriate, and reliable; (2) the Company's forecasts of employment and households are reviewable, appropriate, and reliable; and (3) the Company's forecasts of energy demand for existing and new energy users in the small residential, apartment house, and commercial/industrial sectors are reviewable, appropriate, and reliable.

The Siting Council recognizes the significant strides made by the Company in developing its market simulation model since the last Boston Gas decision. The Siting Council also recognizes that the development of such models and the database necessary for their use is a time consuming process. The Siting Council commends the Company for its efforts thus far and notes the efforts made by the Company to fully document and explain its model in this proceeding. Such efforts enable the Siting Council to more fully appreciate the work done by the Company in developing its market simulation model. The Siting Council also notes that the Company has responded to the concerns identified in the last decision regarding simplifying assumptions and has developed "first versions" of its models based on explicit data and forecasts from a wide variety of sources.

Recognizing that these models are "first versions," the

Siting Council has focused its review in this proceeding on the Company's efforts to develop its models rather than on the specifics of the models and base assumptions. In fact, the Siting Council notes the Company's intentions to continue to enhance the accuracy of its forecasts through continued model development and improvement in input data. The Company described its plans for development of a statistically reliable database of remote metered customers and continued survey work which should enable the Company to more accurately measure and project consumption behavior patterns (Exhs. BGC-21, pp. 12, 37-38, HO-SF-61). In addition, the Company stated that it intends to continue to compare its methodology with those of other, larger gas distribution companies which have more advanced forecasting techniques[17] (id., Exh. HO-SF-57). As the Company implements these anticipated improvements, the Siting Council will be able to more fully evaluate the particular elements of the Company's models.

In sum, the Siting Council finds that, for the purposes of this review, the Company has developed a reviewable, appropriate, and reliable market simulation model which, with continued development, should enable the Company to generate accurate forecasts of sendout in the traditional sectors of its customer base. Accordingly, the Siting Council finds that the Company's forecasts of gross load additions and net load gain generated through the market simulation model are reviewable, appropriate, and reliable for use in developing normal year, design year, and design day sendout forecasts.

3. Cogeneration and Air Conditioning Forecasts

a. Description

The Company stated that it expects to compensate for anticipated reductions in the rate of traditional commercial

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[17] The Siting Council recognizes that use of end-use models is more typically found among electric utilities than among gas utilities and encourages the Company to utilize all appropriate information sources available to it in reviewing possible improvements to its methodology.

and industrial load additions during the forecast period through increases in other markets which may offer greater potential and higher returns (Exhs. BGC-1, p. 9, BGC-21, pp. 33-34). The Company identified cogeneration and gas air conditioning as markets which appear to offer significant opportunities during the forecast period (id.). The Company noted that these markets do not add significantly to winter peaking requirements (id.).

In its initial filing, the Company presented its estimates of cogeneration potential and forecasts of cogeneration demand for the forecast period in two categories: (1) traditional cogeneration used to produce heat/steam and electricity for consumption by the generator; and (2) non-traditional, large cogeneration for production of steam and electricity for resale (Exhs. BGC-1, Sec. 1, pp. 8, 10, BGC-21, p. 30, BGC-45; Tr. 2, p. 89). The Company stated that it assumed cogenerators in the first category would use gas throughout the year, and that those in the second category would require firm supplies for 10 months only, and would not use gas from December 15 through February 15 (id.).[18]

The Company stated that it based its forecasts of cogeneration and gas air conditioning on analyses of total market potential and expected gas penetration prepared by ADL and in-house field marketing personnel (Exhs. BGC-1, Sec. 1, p. 8, BGC-21, p. 14, HO-RR-8, HO-RR-8A - HO-RR-8D). The Company stated that its analysis of traditional cogeneration potential is based on: (1) an assessment of the expected cogeneration load potential by building type; (2) the percentage of the expected cogeneration load which would be fueled by firm gas; (3) the percentage of gross firm gas sales to cogenerators which would not displace existing firm gas sales; and (4) the net increase in firm gas sales possible from

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18/ The Company noted that while it does not currently have a firm rate for the ten month period, it is developing one which it believes will be cost competitive for these projects (Exhs. BGC-1, Sec. 1, p. 8, BGC-21, p. 30).

cogeneration (Exh. BGC-21, p. 30). The Company indicated that its forecast of the non-traditional cogeneration load potential was based largely on market studies performed by in-house marketing personnel and outside firms (Exhs. BGC-21, p. 14, HO-RR-8, HO-RR-8A - HO-RR-8D).

Mr. Tomlinson testified at length regarding the basis of the Company's cogeneration forecast (Tr. 2, pp. 89-109). Mr. Tomlinson noted that "this is the first time the Company had ever forecasted cogeneration per se." (id., p. 94). Mr. Tomlinson indicated that many of the underlying assumptions of the forecasts were developed judgmentally, and were largely based on discussions between ADL and Boston Gas Company personnel. For example, Mr. Tomlinson indicated that, in developing the forecast for traditional cogenerators, assumptions relating to the types of buildings, the typical size of the facilities associated with the different types of buildings, percentage of buildings which would install cogeneration facilities, gas use per facility, annual MWH per facility, estimates of current firm sales displaced by cogeneration, and adjustments for new buildings were largely based on the judgment of Company personnel with experience in the implementation of cogeneration systems (id.). Mr. Tomlinson noted that the Company's assumptions regarding the number of different building types within the Company's service territory were based in part on a 1984 estimate of the number of firms in the Company's service territory from information collected from the MDES (id., p. 90). The Company stated that ADL compared the Company's forecast to several different cogeneration market studies conducted by both the Company and third parties (Exhs. BGC-22, pp. 37-42, HO-SF-32, HO-RR-8, HO-RR-8A - HO-RR-8D). Mr. Tomlinson also stated that the Company was in the process of reevaluating "this whole issue" (Tr. 2, p. 94).

Mr. Tomlinson stated that the Company was particularly concerned with its forecast for large non-traditional cogeneration and noted that, since filing the forecast in this proceeding, a considerable amount of information regarding this potential market had been developed (id., p. 95). Mr. Tomlinson stated that the Company would be working with consultants to "review the power requirements of the different electric utilities in the region and the likelihood of gas being used as a fuel for those" (id., p. 96). In regard to the smaller traditional cogeneration market, Mr. Tomlinson stated that the Company was developing direct marketing programs designed to isolate facilities which likely would convert to cogeneration (id.).

In regard to gas air conditioning, the Company stated that it forecasts additions of about 22.5 BBtu of sendout requirements annually over the forecast period as a result of development of this market (Exhs. BGC-1, Sec. 1, pp. 8, 10, BGC-21, pp. 30-31). The Company stated that it based its forecast of gas air conditioning load additions on: (1) an assessment by ADL of the market potential for gas air conditioning; (2) recent installations of gas air conditioning systems; and (3) estimates of the market potential made by Company field marketing personnel (id.). Mr. Tomlinson noted that the 1985 ADL estimates of market potential at 185 BBtu by 1995 and the Company's estimates of 22.5 BBtu per year are "roughly consistent," and stated that the Company is in the process of "trying to make a hard assessment of how big that market is" (Tr. 2, pp. 109-110; Exh. HO-SF-33).

b. Analysis

The Siting Council recognizes that this is the first time any gas company in the Commonwealth has presented a specific forecast for either the cogeneration or gas air conditioning markets. The Siting Council commends Boston Gas for recognizing the potential opportunities these markets represent, the potential problems associated with incorporating these markets into the Company's demand forecasting models for traditional markets, and the need for a distinct, preliminary methodology for forecasting these markets as they develop.

The Company's methodology for forecasting the traditional cogeneration market is based largely on judgments.

The Siting Council recognizes, however, that, absent specific experience with these new markets, developing such a methodology requires a heavy reliance on judgment. For a methodology based largely on judgment to be appropriate, however, it must be based on appropriate, available information and an understanding of the relevant factors potentially impacting the market being forecasted. The Company's methodology for this market represents a systematic, comprehensive effort to identify those factors which likely will impact the market and to apply applicable forecasting techniques to quantify them. While the Company has developed an appropriate methodology for forecasting the traditional cogeneration market, the lack of reliable input data is a significant weakness to the forecast itself. The numerous assumptions which go into this forecast are based solely on discussions among Boston Gas and ADL personnel, and seriously reduce the level of reliability of the forecast.

Accordingly, the Siting Council finds that the Company has developed a reviewable and appropriate preliminary methodology for forecasting traditional cogeneration load.[19] The Siting Council makes no finding regarding the reliability of the traditional cogeneration forecast for use as an input to the Company's normal year, design year and design day sendout forecasts. The Siting Council ORDERS 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.

In regard to the Company's forecast for the large, non-traditional cogeneration market, the Siting Council notes

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19/ The Siting Council notes that once this market matures, the distinction between the traditional cogeneration market and the traditional commercial/industrial and apartment house markets will diminish, and will lead eventually to its inclusion in the Company's demand forecasting models for those sectors. The Siting Council expects the Company to consider this transition as it develops its forecast model for the traditional cogeneration market, and as it pursues that market.

that a forecast for this market should be based on: (1) an assessment of the market potential; (2) a determination of the desirable market growth goals based on impacts on the Company's existing customers and resources; and (3) a detailed marketing strategy designed to achieve such goals. The Siting Council recognizes that the Company is in the initial stages of developing a methodology to forecast load in the large, non-traditional cogeneration market, and commends the Company for the progress it has made so far. However, the forecast presented by the Company in this proceeding for this market was a result of a preliminary assessment of these critical factors only. It is critical that this large cogeneration forecast be based on an appropriate and reliable methodology due to the significant size of the potential loads in this market, and the consequent significant effect that errors in forecasting this load will have on the Company's total sendout. Here, the Company has failed to establish that its methodology is in fact appropriate and reliable.

Accordingly, the Siting Council finds that the Company has failed to establish that its forecast of the large, non-traditional cogeneration market is a reviewable, appropriate and reliable input to its normal year, design year and design day sendout forecasts. The Siting Council ORDERS the Company to provide, in its next forecast filing, 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.

In regard to the Company's forecast of gas air conditioning, the Siting Council again recognizes the difficulty in forecasting reliably for a market in which the Company has little actual experience. The Company's assertions that its forecast is consistent with recent additions and market potential are poorly supported by evidence in the record in this proceeding, and does not represent an appropriate and reliable forecasting methodology. Accordingly, the Siting Council finds that the Company has failed to establish that its forecast of gas air conditioning load growth represents a reviewable, appropriate, and reliable input to its normal year, design year, and design day sendout forecasts.

4. Regression Equation

To analyze existing aggregate firm sendout, the Company stated that it uses a multiple regression model (Exhs. BGC-1, Sec. 1, pp. 11-13, BGC-11, pp. 2-10; Boston Gas Brief, p. 11). The Company stated that it analyzes sendout data since 1980 for changes in customer usage, but limits its input to the regression model to data from the previous 12 months (Exh. BGC-1, Sec. 1, p. 12). The Company stated that it estimates daily baseload (non-heating) use as the average of daily sendout during July and August, and estimates daily heating use through a multiple regression model based on the difference between total firm daily sendout and firm baseload sendout (id., p. 13). As noted above, the Siting Council, in its last Boston Gas decision, found that the use of a regression model to analyze existing sendout was part of an appropriate sendout forecasting methodology, but found that the methodology used by the Company for specifying its regression model was not appropriate. 1987 Boston Gas Decision, 16 DOMSC at 206. The regression model presented in this proceeding is essentially the same as that reviewed by the Siting Council in its last decision.[20] Here, the Siting Council considers the Company's response to the issues raised in that decision.

a. Description

In reaching its decision in the last proceeding regarding the Company's regression model, the Siting Council identified several elements in the Company's methodology which

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[20] The Company stated that the equation that best describes the sendout of the Company's customer base includes both quantitative and qualitative aspects (Exh. BGC-1, Sec. 1, p. 14). The Company identified daily DD, months with heating DD, and cold spell variables as elements of its regression equation (id.).

appeared to overstate the Company's sendout requirements. Id. Specifically, the Siting Council identified the following aspects of the Company's regression model as being of significant concern: (1) the use of the "most conservative" estimate of baseload sendout, potentially leading to an overstatement of temperature sensitive load; (2) the apparent lack of a systematic method for selecting and evaluating variables for use in the regression equation; (3) the manner in which the Company incorporated ordinary least squares regression assumptions in its evaluation of the regression equation; (4) the use of two and three consecutive cold day variables in the equation without analytical justification, potentially leading to an overstatement of propane and LNG requirements; (5) the identification of non-linear data represented with a linear equation as a possible cause of underprediction in cold weather, and the practice of compensating for that underprediction through the use of a four percent cold snap factor. Id., pp. 204-205.

The Company presented extensive documentation and testimony during the course of this proceeding in response to these concerns (Exh. BGC-11). The Company asserted that this evidence establishes that its regression equation is in fact a reviewable, appropriate and reliable element of its overall forecasting methodology (id.; Boston Gas Brief, p. 11).

In regard to the first issue relating to the possibility of overstating temperature sensitive load, the Company presented analyses showing that there is no significant impact on the ability to predict heating sendout on an annual or monthly basis when the 90-day baseload period is used instead of the two-month baseload period (Exhs. BGC-12, BGC-13). The Company stated that it decided to use the two-month period rather than the 90-day period to determine baseload because it resulted in a more accurate assessment of total sendout and not because it was "more conservative" (Exhs. BGC-1, Sec. 1, p. 13, HO-SF-34; Tr. 1, pp. 107-108).

In regard to the Company's method for selecting and evaluating variables for use in its regression equation, Ms. Michalek stated that the gas-supply planning staff and the gas-dispatching staff meet on a biweekly basis throughout the winter to discuss patterns of consumption and supply use (Tr. 1, p. 113). Ms. Michalek indicated that through these meetings, any variations in consumption behavior patterns would be identified, enabling the Company to evaluate the impact of including representative variables in a revised regression equation (id.). Ms. Michalek identified EDD, temperature lag on all days, and the extended baseload period as variables which the Company analyzed but rejected, and stated that since its initial filing in this proceeding, it had evaluated and incorporated a weekday/weekend variable in its equation (Exh. HO-RR-3; Tr. 1, pp. 110-112). In addition, the Company stated that it evaluated variations the its current DD and month variables in its analysis of the current equation (Exh. HO-SF-36).

The Company stated that it determines which variables to include based on their statistical significance in explaining historical sendout (Exhs. BGC-11, p. 4, HO-RR-3). Ms. Michalek noted that the Company uses its regression equation to normalize company-wide daily sendout for weather differences, not just the sendout from a sample customer group or geographic location (Exh. BGC-11, p. 4). As a result, the Company maintains that the goodness of fit of the entire equation to actual data is the most important criteria (id.). Ms. Michalek also noted that temperature is the primary explanatory variable and that, when DD are combined with the remaining variables in the current equation, approximately 98 percent of sendout is explained (Exh. HO-RR-3).

Ms. Michalek noted that the results of on-going studies of customer behavior (such as the residential metering study) may lead to the identification of new variables, and stated that the Company will continue to review both the variables currently included in its equation and any new variables which it identifies to determine their significance (Tr. 1, pp. 111-114).

In regard to the manner in which the Company incorporated regression assumptions in its evaluation of the regression equation, the Company presented a detailed discussion and supporting analyses in response to the specific issues raised in the last decision (Exhs. BGC-11, pp. 5-7, BGC-14, BGC-15, BGC-16). These analyses indicate that the Company has applied appropriate ordinary least squares regression assumptions in its evaluation of its regression equation (id.). Specifically, the Company stated that its analyses establish that the equation includes relevant variables and is based on accurate data (Boston Gas Brief, p. 11). The Company stated that it reached this conclusion because: (1) there are no discernable error patterns which would suggest the presence of heteroskedasticity; (2) there is no evidence of positive or negative autocorrelation as evidenced by Durban-Watson statistics; (3) there is no evidence of correlation between independent variables and estimation errors; and (4) there is no evidence of perfect correlation among the independent variables (Exh. BGC-11, pp. 5-7).

The Company also presented documentation in support of its assertion that the use of two- and three-day cold spell variables in the regression equation is statistically justified (id., pp. 7-8, Exh. BGC-15).[21] The Company stated that these variables reflect historic increases in customer use as a result of successive cold days during cold winters, and noted that the variables have been statistically significant during cold winters (Exhs. BGC-1, Sec. 1, p. 15, BGC-11, pp. 7-8). Ms. Michalek stated that the 1987-88 winter included prolonged cold periods which confirm the continued validity of use of these variables (Tr. 1, pp. 117; Exh. HO-RR-4). Ms. Michalek noted that use of this variable is especially desirable in design year planning due to supply constraints during cold weather (id.; Exh. BGC-11, p. 8).

21/ The Company stated that if a specific day's temperature is 30 degrees or below, and is colder than the prior day's temperature, then the two-day variable is used (Exh. BGC-1, Sec. 1, p. 15). The Company stated that the three-day variable is used if a 30 degree or colder day occurs following two days that are also colder than thirty degrees (id.).

Ms. Michalek stated that she believed that the cold-spell variables have "a lot more statistical justification than the cold-snap factor" (Tr. 1, p. 115). The Company asserted that continued use of a cold snap factor is warranted however, due to the fact that its model continues to underestimate actual sendout for extremely cold days (40 DD or colder) (Exhs. BGC-1, Sec. 1, p. 16, BGC-11, pp. 8-9). The Company noted that the 1987-88 winter was the first time since the early 1980's that periods of extreme cold temperatures occurred which allowed the Company to test the validity of its cold-snap factor (id., Exhs. BGC-18, BGC-19, HO-RR-4; Tr. 4, pp. 109-112). The Company stated that its analyses of the 1987-88 winter indicate that actual sendout was higher than forecasted sendout even with the four percent cold snap factor added (Exh. BGC-11, p. 9). As a result of the near design characteristics of portions of the 1987-88 winter,[22] the Company stated that it believes that the sendout patterns of that year already partially account for the customer behavior patterns which the cold-snap factor is designed to represent (id., Exh. BGC-1, Sec. 1, p. 16). Therefore, in developing the sendout projections for this forecast, the Company used a regression equation based on the period April 1, 1987 through March 31, 1988, and applied only a two percent cold snap factor instead of its historic four percent factor (id.; Tr. 5, p. 8).

b. Analysis

The Siting Council commends the Company on its comprehensive response to the issues raised in the last proceeding. Many of these responses have alleviated the Siting Council's concerns expressed in the last decision. In particular, the Company has established that its use of a

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22/ The Company noted that its design year includes 33 days (excluding the design day) which are 40 DD or greater (Exhs. BGC-11, pp. 9-10, BGC-1, Sec. 1, p. 16). The Company stated that the 1987-88 winter included 16 days at 40 DD or greater (id.).

two-month baseload period, application of ordinary least squares assumptions in developing its equation, and use of the cold spell variables are appropriate at this time.

In regard to the selection and evaluation of variables for use in the regression model, the Siting Council acknowledges that the process of identifying variables for consideration is difficult, and notes that routine meetings between departments are an appropriate element of the identification process. The Siting Council also notes that the addition of the weekday/weekend variable demonstrates the Company's active efforts to improve its regression equation. However, the Siting Council expects a Company the size of Boston Gas to have a more formalized and sophisticated process to ensure continued review and enhancement of such a critical element of its overall forecasting methodology. The Siting Council expects that the Company will continue to evaluate means to improve its regression model including: (1) incorporation of information developed through customer metering studies; (2) incorporation of customer use patterns identified through the market simulation model; and (3) periodic review of methodological changes such as the use of additional years of data, or consideration of non-linear equation forms.

In regard to the Company's use of a cold snap factor to account for non-linear customer usage patterns at extreme temperatures, the Siting Council remains concerned that the Company has not fully considered more statistically justifiable means of incorporating this customer response in its model. Obviously, use of such a factor must be carefully considered relative to the specific weather patterns associated with the sendout data used in developing the model. Here, the Company has considered this relationship in development of its model based on sendout data from the 1987-88 year. While the reduction of the cold snap factor for this model from four percent to two percent is appropriate in light of the near design weather conditions during the 1987-88 heating season, the Siting Council expects the Company to provide, in its next forecast filing, an evaluation of variables designed to capture this behavior, and inclusion of such variables in its model if statistically justified.

Accordingly, the Siting Council finds that the Company's use of a multiple regression model continues to be an appropriate methodology for analyzing existing sendout. In addition, the Siting Council finds that the Company has established that its analysis of existing aggregate firm sendout is a reviewable, appropriate, and reliable input for use in developing the Company's normal year, design year and design day sendout forecasts.

5. Normal Year and Design Year Sendout Forecasts

The Company presented its forecasts of firm normal year and design year sendout in its initial filing (Exh. BGC-1, Sec. 2, Tables G-1 - G-5). The Company stated that the forecasts were developed using the Company's regression model, market simulation model, and forecasts of cogeneration and gas air conditioning. The Company described the process used to develop its annual forecasts based on these models (Exhs. BGC-1, Sec. 1, p. 17, BGC-58, pp. 2-3, HO-SF-38, HO-SF-39; Tr. 2, pp. 132-135). The Company stated that it first develops an estimate of sendout under normal conditions for the base year using its regression model (id.). The Company then adds the specific magnitudes (MMcf) and type of loads (heating or non-heating) forecasted by the market simulation model and the cogeneration and air conditioning forecasts for each year of the forecast period (id.).

The Company stated that forecasts of baseload are added evenly throughout the year while forecasts of heating load are spread out across the year based on the heating load patterns in the regression equation (id.). The Company stated that for design year forecasts, the heating load additions are assumed to be 10 percent higher than projected to reflect the ten percent difference between normal year and design year daily degree days (Exh. BGC-1, Sec. 1, p. 17). The Company also stated that for design year forecasts, the Company adds back the deduction made in the market simulation model for conservation because "conservation is primarily behavorial in the short-term" (Exh. BGC-58, p. 3). Mr. Tomlinson noted that the Company allocates the annual cogeneration forecast based on assumptions regarding the maximum demand during the heating season, and then spreading the remainder out over the non-heating season (Tr. 2, pp. 134-135).

The Company revised its sendout forecast during the course of this proceeding to reflect the most recent regression equation coefficients based on actual sendout from November 1987 through October 1988 (Exhs. HO-RR-16, HO-RR-17; Tr. 5, pp. 38-32). In addition, the Company's revised sendout forecast reflects changes in its large cogeneration forecast (id.). The Company's design year forecast is presented in Table 1.

The Company stated that its interruptible forecast represents firm gas pipeline capacity available for sales to interruptible customers after meeting firm requirements and storage refill requirements (Exh. HO-SF-40; Tr. 5, pp. 31-32). The Company noted that in all years, these amounts do not exceed the demand for interruptible sales (id.).

In previous sections of this decision, the Siting Council has found that: (1) the Company's normal year and design year planning standards are appropriate and reliable; (2) the Company's forecasts of gross load additions and net load gain generated through the market simulation model are appropriate and reliable for use in developing normal year and design year sendout forecasts; and (3) the Company's analysis of existing aggregate firm sendout is an appropriate and reliable input for use in developing the Company's normal year and design year sendout forecasts. In addition, the Siting Council was unable to find that the Company's forecasts of traditional cogeneration, large cogeneration, and gas air conditioning are a reliable input to the Company's normal year and design year sendout forecasts.

The Siting Council recognizes that cogeneration and gas air conditioning represent new markets for gas companies in general. As such, forecasting methods for these markets are, at this point in time, necessarily simplistic and undeveloped. In addition, the size of these markets relative to total Company sendout is still small. The Siting Council notes, however, that as these markets grow, the Company will be expected to fully justify its forecasting methodology with respect to these markets.

Accordingly, the Siting Council finds that, on balance, the Company's normal year and design year sendout forecasts are reviewable, appropriate, and reliable.

6. Design Day Sendout Forecast

The Company's methodology for forecasting design day requirements is the same as the methodology for forecasting design year requirements except that the Company prepares the forecast for the design day only using the Company's design day assumptions of a 73 DD day in January following two consecutive cold days (Exh. BGC-9, p. 23). Therefore, the Siting Council finds that the Company's methodology for forecasting design day requirements is reviewable and appropriate. The Siting Council found in Section II.C.4.b, above, that the Company's design day planning standard was appropriate and reliable. Accordingly, the Siting Council finds that the Company's design day sendout forecast is reviewable, appropriate, and reliable.

E. Conclusions on 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 reliable; and (3) the Company's design day sendout forecast is reviewable, appropriate, and reliable.

Accordingly, the Siting Council hereby APPROVES the 1988 sendout forecast of Boston Gas Company.

In approving the Company's sendout forecast the Siting Council notes the significant efforts made by the Company since our last decision to improve its sendout forecast. In particular, the development of planning standards in this case represents an adequate and long awaited response to the Siting Council's requirements that gas companies establish appropriate levels of reliability for supply planning and consider the cost/reliability tradeoff associated with such levels of reliability. Further, Boston Gas has become a leader in the development of appropriate forecasting methodologies for the gas industry in Massachusetts, as evidenced by its development of end-use market simulation models as part of its overall forecasting methodology.

At the same time, the record in this case indicates that improvement is necessary in several areas of the Company's sendout forecasting methodology, such as the Company's weather database, and its forecasts of non-traditional cogeneration and air conditioning markets. The Siting Council expects the Company to make continued improvements in these areas in future forecast filings.

III. ANALYSIS OF THE SUPPLY PLAN

A. Standard of Review

The Siting Council is charged with ensuring "a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost." G.L. c. 164, sec. 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.[23] 1989 Bay State Decision, EFSC 88-13, p. 35; 1989 Fitchburg Decision, EFSC 86-11(A), p. 27; 1988 ComGas Decision, 17 DOMSC at 108; 1987 Bay State Decision, 16 DOMSC at 308; 1987 Berkshire Decision, 16 DOMSC at 71; 1987 Boston Gas Decision, 16 DOMSC at 213; Fall River Gas Company, 15 DOMSC 97, 111 (1986) ("1986 Fall River Decision"); 1986 Fitchburg Decision, 15 DOMSC at 54-55; 1986 Holyoke Decision, 15 DOMSC at 27; 1986 Westfield Decision, 15 DOMSC at 72-73; Berkshire Gas Company, 14 DOMSC 107, 128 (1986) ("1986 Berkshire Decision").

In its review of a gas company's supply plan, the Siting Council first reviews a company's overall supply planning process. An appropriate supply planning process is essential to the development of an adequate, least-cost, and low-environmental impact resource plan. Pursuant to this standard, a gas company must establish that its supply planning process enables it: (1) to identify and evaluate a full range of supply options; and (2) to compare all options -- including conservation and load management ("C&LM") -- on an equal footing. 1989 Bay State Decision, EFSC 88-13, p. 35; 1989 Fitchburg Decision, EFSC 86-11(A), pp. 51-52; 1988 ComGas Decision, 17 DOMSC at 138-139; 1987 Bay State Decision, 16 DOMSC at 323; 1987 Berkshire Decision, 16 DOMSC at 85; 1987 Boston Gas

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[23] 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.C.3, below.

Decision, 16 DOMSC at 252; 1986 Fall River Decision, 15 DOMSC at 115.[24]

The Siting Council next reviews a gas company's five-year supply plan to determine whether that plan is adequate to meet projected normal year, design year, peak day, and cold-snap firm sendout requirements.[25] In order to establish adequacy, a gas company must demonstrate that it has an identified set of resources which meet its projected sendout 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. 1989 Bay State Decision, EFSC 88-13, p. 36; 1989 Fitchburg Decision, EFSC 86-11(A), p. 28; 1988 ComGas Decision, 17 DOMSC at 108; 1987 Bay State Decision, 16 DOMSC at 308; 1987 Berkshire Decision, 16 DOMSC at 71; 1987 Boston Gas Decision, 16 DOMSC at 312.

Finally, the Siting Council reviews whether a gas company's five-year supply plan minimizes cost. A least-cost supply plan is one that minimizes costs subject to trade-offs with adequacy and environmental impact. 1989 Bay State

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[24] In 1986, G.L. c. 164, sec. 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 ComGas 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 meet projected sendout requirements.

[25] 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: 1989 Bay State Decision, EFSC 88-13, p. 36, n. 19; 1989 Fitchburg Decision, EFSC 86-11(A), p. 28; 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.

Decision, EFSC 88-13, p. 36; 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; See: Massachusetts Electric Company, 18 DOMSC 295, 337 (1989) ("1989 MECo 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. Previous Supply Plan Review

In the 1987 Boston Gas Decision, 16 DOMSC at 270-271, the Siting Council rejected Boston Gas' supply plan and ordered the Company to include in its next forecast filing:[26]

> 2. (1) a reevaluation of its Commercial Point and Lynn liquefaction capabilities that adequately considers historical liquefaction experience, (2) a demonstration that its reevaluated liquefaction capabilities are sufficient to meet forecasted liquefaction requirements in all forecast years, and (3) if the Company cannot demonstrate such liquefaction capability, a proposed plan for securing adequate LNG refill capability and a schedule for implementing that plan;
>
> 3. a complete argument demonstrating its ability, on a daily basis during the design year in [the Company's next] filing that requires the most propane, to contract for propane supplies, to receive such supplies from its supplier, to transport those supplies to the necessary propane dispatch facilities, to dispatch the propane, and to maintain adequate propane inventories;
>
> 4. (1) an estimation and detailed analysis of its maximum ability to use propane given all the procurement, storage, and dispatch constraints, (2) an identification of the critical factor(s) determining that maximum amount, and (3) propane dispatch sensitivity analyses for a reasonable range of estimates for such critical factors;
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> 5. a justification for any terminalling rights at Sea-3's Newington, NH propane terminal above the Company's maximum ability to use propane as a supply;

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[26] The numbers preceding each order correspond to the numbers assigned in the 1987 decision.

6. an updated cold snap analysis;

7. a demonstration that, under assumed design day conditions, it has the ability to use (1) all of its vaporizers simultaneously and at full capacity at its Commercial Point LNG facility, (2) all of its vaporizers simultaneously and at full capacity at its Lynn LNG facility, (3) all of its vaporizers simultaneously and at full capacity at its Salem LNG facility, and (4) all of its SNG and propane-air production capacity simultaneously and at full capacity at its Everett propane plant;

8. a uniform design day planning standard for use in sendout forecasting, supply planning and distribution system planning;[27]

9. a long-term plan for reinforcing and redesigning its entire distribution system appropriate to a level of reliability equivalent to that amount assumed in the supply plan.[28]

In addition, in the 1987 Boston Gas Decision the Siting Council noted serious deficiencies in Boston Gas' supply planning process. The Siting Council criticized the Company for failing to establish that its supply planning process treats all resource options on an equal footing, stating that "Boston Gas has provided virtually no information regarding how it evaluates the costs and benefits of Company-sponsored conservation strategies against the costs and benefits of obtaining new supplies." Id., at 252-253. With regard to

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27/ In Section II.C.4, above, the Siting Council found that the Company has established that its design day planning standard of 73 DD for use in sendout forecasting and supply planning is reviewable, appropriate, and minimally reliable. In Section III.E.4, below, the Siting Council evaluates this standard for use in the Company's distribution system planning.

28/ The Siting Council also ordered the Company to develop a clear and specific plan for minimizing the risk and extent of a service interruption to firm customers during the 1987-88 heating season. 1987 Boston Gas Decision, 16 DOMSC at 268, 271. This plan was to be filed by October 15, 1987. Id. In response to this order, the Company filed the plan on that date (Exh. HO-3), and an amendment to that plan on November 6, 1987 (Exh. HO-2).

least-cost supply planning, the Siting Council stated that the Company "made assertions without providing any support, reasoning or documentation which would allow the Siting Council to evaluate the Company's conclusions." Id., at 247. The Siting Council also noted that Boston Gas failed to provide required cost studies for the Boundary Gas, Inc. ("Boundary") and Alberta Northeast Gas Limited ("ANE") pipeline projects and concluded that "without formal analysis and documentation of the costs and benefits of new supplies, the Siting Council's mandate to verify that supply planning decisions are optimal is violated, and further, the Company denies itself of an organized method of analyzing and re-affirming past decisions." Id., at 249.

The Company's compliance with these orders is discussed in Sections III.D.1.a, 3, and 4, below.

C. 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. 1989 Bay State Decision, EFSC 88-13, p. 38; 1989 Fitchburg Decision, 86-11(A), pp. 54-55; 1989 MECo Decision, 18 DOMSC at 336-338, 348-370; Boston Edison Company, 18 DOMSC 201, 224-226, 250-281 (1989) ("1989 BECo Decision"); Eastern Edison Company, 18 DOMSC 73, 100-103, 111-131 (1988) ("1988 EECo Decision"); 1987 Boston Gas Decision, 16 DOMSC at 71-72. 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. 1987 Bay State Decision, 16 DOMSC at 332. For the Siting Council to determine that a gas company's supply planning process is appropriate, the process must be fully documented. 1987 Boston Gas Decision, 16 DOMSC at 247, 249;

1987 Bay State Decision, 16 DOMSC at 332; 1987 Berkshire Gas Decision, 16 DOMSC at 84.

The Siting Council's review of a gas company's supply planning process has focused primarily on whether: (1) the process allows companies to adequately consider conservation and load management ("C&LM") options; and (2) the process treats all resource options -- including C&LM options -- on an equal footing. 1989 Bay State Decision, EFSC 88-13, p. 35; 1989 Fitchburg Decision, EFSC 86-11(A), pp. 51-52; 1988 ComGas Decision, 17 DOMSC at 138-139; 1987 Bay State Decision, 16 DOMSC at 323; 1987 Berkshire Decision, 16 DOMSC at 85; 1987 Boston Gas Decision, 16 DOMSC at 252; 1986 Fall River Decision, 15 DOMSC at 115.

In the 1989 Fitchburg Decision, the Siting Council clarified its standard of review, noting that our review of a gas company's supply planning process, like our review of an electric company's supply planning process, must include an analysis of the company's documented process for identifying and evaluating resource options. (EFSC 86-11(A), pp. 54-55). Only through a comprehensive analysis of a company's process for identifying and evaluating resource options can the Siting Council determine specifically whether: (1) the process allows for the adequate consideration of C&LM; (2) the process treats all options on an equal footing; and (3) the process as a whole enables the company to achieve an adequate, least-cost, and low environmental impact supply plan.

In the 1989 Bay State Gas Decision, EFSC 88-13, p. 39, the Siting Council further clarified its standard of review, specifying that in reviewing a gas company's process for identifying and evaluating resources, the Siting Council determines whether the company: (1) has a process for compiling a comprehensive array of resource options -- including pipeline, supplemental supply, conservation, load management, and other resources; (2) has established appropriate criteria for screening and comparing resources within a particular supply category; and (3) has a mechanism in place for comparing all resources on an equal footing, i.e., across resource categories.[29]

The Siting Council recognizes that fewer resource options may exist for gas companies than for electric companies and consequently that the resource identification and evaluation process may be considerably less complex for gas companies than for electric companies. However, the Siting Council concludes that the general framework for reviewing the supply planning process identified above is applicable to gas companies. We also recognize that each gas company will have different supply planning options and needs and that each company's supply planning process will be different in some respects.

While the Siting Council acknowledges that the organization of our review in this case differs somewhat from our previous reviews of the Company's filings, this reorganization does not establish new regulatory standards nor place additional burdens on the Company. Rather, our intent is to better track the manner in which gas company resource decisions are actually made, and to underscore our emphasis on the importance of the planning process as the foundation for the implementation of a least-cost supply plan.

2. Identification and Evaluation of Resource Options

Boston Gas stated that it has three principle objectives in planning for new supplies, which are, in order of priority: (1) to enable the Company to meet the current and future needs of its firm customers; (2) to maintain an appropriate balance of pipeline and supplemental supplies; and (3) to meet the needs of interruptible customers during off-peak periods (Exhs. BGC-2, p. 5; BGC-75, p. 4; Tr. 1, pp. 22-25, 30, 48).

The Company indicated that it has recently undertaken a

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[29] The Siting Council's review of whether the application of the Company's planning process has resulted in a least-cost plan is addressed in Section III.F, below.

number of changes within its supply planning operations, such as the formation of an interdepartmental load research committee and the formation of a new C&LM department (Tr. 6, pp. 106, 153; Exh. HO-SP-35, p. 27). According to Mr. Luthern, the purpose of the load research committee is "to take a look at our sendout figures, their marketing expectations, [and] where load management and conservation actions can be implemented" on a "very integrated, coordinated basis" (Tr. 6, p. 106). Once a supply project has been identified and evaluated by the committee, the conclusions are presented to top management, including the vice presidents of marketing, supply and production, and operations, for a final decision (id.). The Company's new C&LM department is discussed in Section III.C.2.c, below.

The Company did not specifically identify a group of resource sets (generic types of resources) available to it but throughout the record it generally divided existing and potential supplies into three groups: (1) firm pipeline gas and supplemental gas supplies, including LNG and propane; (2) spot gas; and (3) C&LM. Because the Company's identification and evaluation process differs somewhat for each of these types of resources, the Siting Council reviews them separately below.

a. Firm Pipeline and Supplemental Gas Supplies

i. Description of Supply Planning Process

Mr. Luthern provided a detailed explanation of the Company's general approach to supply planning for traditional firm pipeline and supplemental gas supplies. Mr. Luthern stated that in order to identify new pipeline supply options, the Company is in constant contact with various pipelines, customer groups, suppliers and marketers, and that, in addition, the Company remains aware of possible supply opportunities through its active participation in the spot market (Exh. BGC-76, p. 4). The Company stated that it also identifies suppliers of LNG and propane on an ongoing basis (Exh. HO-SP-38).

Mr. Luthern stated that once Boston Gas receives preliminary information on a possible new supply source, the Company makes a preliminary estimate of the potential for adding new load and a determination of the extent to which the new project could meet that load (Exh. BGC-75, p. 4). Mr. Luthern also stated that if the supply option appeared to be attractive on a preliminary basis, the Company would then proceed to conduct more detailed marketing, financial, and operational studies to determine the Company's desired level of participation in the project (id., pp. 4-6).

The Company indicated that it employs several criteria in its evaluation of potential pipeline or supplemental gas additions to its supply portfolio, including cost, reliability, diversity of supply, operational considerations, competitive advantage, and timing (Exh. HO-SP-38). The Company stated that it currently considers cost and reliability to be its most important criteria (id.).

With regard to cost, Mr. Tomlinson stated that the Company would not contract for a new supply unless that supply would result in lower overall rates for its firm customers over time (Tr. 2, pp. 124-125; Tr. 3, pp. 73-74). With regard to reliability, the Company indicated that an unreliable supply which could potentially result in a gas delivery shortage would be considered unacceptable (Exh. HO-SP-38).

With regard to operational considerations, the Company stated that such factors as the point in the Company's distribution system where potential supplies would be delivered is an important evaluation criterion (id.). With regard to supply diversity, the Company stated that it takes into account the source of the gas supply (e.g., domestic or Canadian) in its supply planning process (id.).

With regard to competitive advantage, the Company stated that the addition of new pipelines to serve the Northeast, such as Champlain and Iroquois, would increase competition between gas providers in the region (id.). Boston Gas asserted that such increased competition should lead to lower gas prices and an increased level of service for the Company (id.).

Finally, with regard to timing, the Company stated that the coincidence of marketing opportunities with potential new supplies plays a role in its evaluation of a supply option (id.).

ii. Analysis

The Siting Council finds that the Company's supply planning process for new pipeline and supplemental gas supplies is appropriate. This process allows Boston Gas to identify a variety of potential pipeline and supplemental resources. Moreover, Boston Gas has developed a reasonable set of price and non-price criteria, which allows the Company to evaluate the supply options that it has identified in order to determine which option(s) to pursue.

The Company's criterion for cost-effectiveness is appropriately designed to ensure that the addition of a new supply will contribute to lower customer rates over time. The Company's use of non-price criteria is appropriate and ensures that the Company examines potential pipeline and supplemental supplies across a variety of relevant dimensions in its evaluation process. However, the Company's descriptions of its selected non-price criteria and how it evaluates tradeoffs among non-price criteria and between price and non-price criteria are somewhat vague. In the future, the Siting Council expects Boston Gas to provide a more explicit description of these non-price criteria and an explanation of how the Company balances tradeoffs between its various evaluation criteria in its supply planning process.

Accordingly, the Siting Council finds that the Company's process for identifying and evaluating firm pipeline and supplemental gas supplies is an appropriate means for deciding among such supply options.

b. Spot Gas Supplies

i. Description of Supply Planning Process

Ms. Michalek indicated that Boston Gas has developed a process for identifying and evaluating spot gas purchases that is distinct from the Company's supply planning process for firm pipeline and supplemental supplies (Exh. BGC-58, p. 6).

The Company stated that it utilizes a monthly bidding process to identify and evaluate spot gas supplies (Exhs. HO-SP-17, HO-SP-54). Under this process, the quantity of spot gas required is estimated by the Company prior to the start of each month of the spot gas season (Exh. HO-SP-17).[30] The Company stated that the factors that it considers in formulating this estimate include firm and interruptible sendout requirements, the need for storage refill, the price of alternative fuels, the availability of pipeline transportation, and system operating constraints (id.; Tr. 5, p. 116).

Boston Gas further stated that approximately ten days before each "bid day," the Company mails notification letters to approximately 60 gas producers and marketers notifying them that the Company is seeking bids for gas (Exh. HO-SP-54). On bid day, Boston Gas receives specific proposals to provide spot gas supplies (id.). The Company stated that it then ranks these bids by price and generally chooses the lowest-cost supplier, although it also considers such factors as the reliability of the supplier, the point at which gas is to be received, and the status of the gas transportation contract (Tr. 5, p. 114).

Ms. Michalek stated that the Company has been very successful in reducing gas costs to its customers through its spot market bidding process (Exh. BGC-58, p. 7). According to Ms. Michalek, in 1987, the year that the Company instituted its bidding system, the Company obtained nearly 40 percent of its

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[30] The Company stated that the spot gas season normally extends from April 1 through October 31, the period when interruptible transportation generally is available on the Algonquin and Tennessee pipelines (Exh. HO-SP-54). Pipeline capacity for the transportation of spot gas generally is not available during the winter months because of firm sales commitments (id.). The Company stated that it also occasionally obtains spot LNG in the winter from DOMAC, since these supplies do not require any pipeline transportation (Tr. 5, pp. 115, 118).

total supplies from spot gas and achieved a total savings of approximately $7.7 million over firm pipeline costs (id.). Mr. Luthern stated that the Company saved a total of $11.6 million in 1988 through spot market purchases (Exh. BGC-75, p. 21).

ii. Analysis

The Siting Council finds that the supply planning process used by Boston Gas for spot supplies is appropriate considering the current limitations on interruptible gas transportation in the region. Further, it is appropriate for Boston Gas to have a process to identify and evaluate spot supplies that is distinct from the process it utilizes for firm pipeline and supplemental supplies because of the significant differences between these supply types, including cost, reliability, contract length, and availability.

The Company's formal bidding process is an appropriate means for identifying least-cost spot gas supplies. A formal bidding process such as this is commendable, as it significantly increases the likelihood that the Company in fact will be able to identify and obtain least-cost spot supplies. In evaluating such short-term, non-heating season transactions, it is appropriate for Boston Gas to focus primarily on cost, while also considering such factors as the reliability of the gas supplier and the gas receipt point. 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 for deciding among spot supply options.

c. Conservation and Load Management

i. Description of Supply Planning Process

The Company indicated that it is actively engaged in the process of identifying and evaluating a wide range of potentially cost-effective C&LM programs (Exhs. HO-SP-59, HO-SP-66A). Boston Gas stated that, as an initial step, the

Company established a new internal C&LM department in February 1989 (Exhs. HO-SP-35, p. 37, HO-SP-59). The Company indicated that this department is responsible for developing and implementing cost-effective C&LM programs (id.; Tr. 3, pp. 10, 11). The Company stated that in 1989 it also hired a consulting firm, PLC, Inc., to identify on a preliminary basis the types of C&LM measures which potentially may be cost-effective (Exhs. HO-SP-59A, HO-SP-35 p. 27; Tr. 3, pp. 38-43, 46-48). The Company provided the Siting Council with a lengthy list of measures identified by PLC, Inc. (Exh. HO-SP-59A).

Boston Gas stated that its C&LM progam department is presently in the process of identifying the potential for C&LM for various customer classes (Exh. HO-SP-59). Mr. Tomlinson stated that the Company's identification process for C&LM measures "starts with an understanding of what different types of conservation measures might cost" (Tr. 3, p. 38). Mr. Tomlinson also stated that the identification and evaluation of potentially cost-effective C&LM programs requires the Company to conduct a great deal of up-front research on such topics as the cost, efficiency, and potential energy savings associated with various C&LM measures (id.).

The Company described its overall process for C&LM planning and implementation as consisting of several steps including: (1) determining what types of C&LM programs might be cost-effective for different customer groups based on industry and technical data; (2) assessing whether similar opportunities exist within the Company's service territory; (3) determining the expected cost-effectiveness of specific potential programs; (4) implementing those programs determined to be cost-effective; (5) monitoring program results; and (6) updating the data and methodology used to evaluate C&LM continually as experience and research dictate (id.; Exh. HO-SP-66A, p. 1).

implemention throughout an initial implementation period and expects to move to full-scale implementation during the 1990-91 heating season (id., pp. 4, 5).

Other facets of the implementation portion of the Company's C&LM Plan include: (1) communication of C&LM information throughout the Company in order to enhance program implementation; (2) integration of external resources, such as private engineering and energy firms, into the Company's overall marketing and implementation strategy; and (3) working with the Company's customers to identify potential C&LM opportunities (id., p. 5).

The Company further stated that in order to carry out the C&LM Plan, it has committed additional staff resources to its C&LM department and has contracted for technical assistance with two consulting firms: (1) Energy Systems Research Group, a non-profit energy consulting firm, which will assist the Company in developing and implementing the C&LM Plan; and (2) Energy Investments, Inc., an engineering consulting firm, to perform a market and technical study ("EII study") of the Company's customer base (id., pp. 2, 4). In addition, the Company is co-sponsoring a Massachusetts Natural Gas Council study ("MNGC study") to identify existing gas C&LM programs across the U.S. (id., p. 4; Exh. HO-SP-66B). The Company stated that it expects that the combined results of the EII and MNGC studies will provide it with quality information on C&LM technical potential, market design and customer program acceptance and participation and that the EII study will provide it with a firm foundation of data for the development of R&D programs for all customer groups within in its service territory (Exh. HO-SP-66A, p. 4).

(B) C&LM Evaluation Process

The Company's current process for evaluating C&LM programs was developed during the course of the Company's most recent rate case before the Massachusetts Department of Public Utilities ("MDPU").[31] See: Boston Gas Company, D.P.U. 88-67, (Phase 2) (1989). In that docket, the Company originally proposed a methodology to evaluate potential C&LM programs based on price as well as non-price criteria (Exh. HO-SP-35, pp. 4-23). Under this methodology, the Company proposed to use a two step process for evaluating potential C&LM investments: (1) determine C&LM cost-effectiveness by comparing the expected cost of each potential C&LM program to the avoided cost of new gas supplies; and (2) analyze four non-price criteria -- timing, system optimization, risk, and externalities -- for potential C&LM programs within a 15 percent bandwidth above or below avoided cost and compare these with the non-price attributes of the avoidable gas supply (id.; Exh. HO-SP-60). The Company stated that it would proceed with C&LM investments that it judged to be cost-effective under its proposed methodology (Exh. HO-SP-35, pp. 19, 37).

Subsequently, during the period that the MDPU decision was pending, Boston Gas revised its proposed methodology to exclude the evaluation of non-price criteria (Exh. HO-SP-60). Under this revised proposal, the Company would, on an interim basis, employ a single criterion -- price relative to avoided costs -- to evaluate potential C&LM programs (Tr. 2, p. 10, Tr. 3, p. 22). As a justification for this change, Boston Gas stated that non-price criteria were extremely difficult to quantify and that the value of such criteria was greatly dependent on the ultimate use of the conserved gas (Exh. HO-SP-60; Tr. 3, pp. 32-35). The Company stated that there are many complicated issues related to the use of non-price criteria which require further analysis by both the Company and regulators and suggested that such issues be resolved through ongoing Company research and/or MDPU hearings and ratecases (Tr. 2, pp. 9-10, Tr. 3, pp. 22, 29-32). The

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31/ The Siting Council hereby takes administrative notice of Boston Gas Company, D.P.U. 88-67, (Phase 2) (1989).

Company also stated that the quantification of non-price criteria is likely to be a lengthy process (Tr. 3, p. 32).

In its final order, the MDPU accepted Boston Gas' revised evaluation methodology as an appropriate interim means for evaluating potential C&LM programs. See Boston Gas Company, D.P.U. 88-67, (Phase II), pp. 110-123 (1989). Consequently, the Company presently is employing this single-criterion methodology to evaluate potential C&LM programs.

ii. Analysis

The Siting Council notes that the implementation of cost-effective C&LM programs still is largely in the developmental stage throughout the gas industry. Boston Gas has demonstrated that it currently is conducting or sponsoring ground-breaking research in the identification and evaluation of potential C&LM programs. This work should enable the Company to determine which potential C&LM programs are the most cost-effective programs for its customers and to implement such programs. The Company's efforts also should serve as a good model and potential source of information for smaller gas companies which may be lagging in the identification and implementation of C&LM programs.

In particular, the Company's C&LM Plan is an impressive indication of the Company's committment to identify and implement cost-effective C&LM resources. The Plan sets forth an aggressive schedule for moving from planning to R&D using pilot programs and then to full-scale implementation of C&LM programs for all customer sectors.

The Company appropriately decided to initiate its C&LM Plan by holding a series of meetings to examine the experiences of electric utilities with C&LM program development and implementation and to gather information and ideas from a number of relevant organizations, such as energy consulting firms, engineering firms, and regulators. The Company's decision to work with individual customers to identify potential C&LM opportunities also is commendable. The information gathered through these efforts, together with data derived from the EII and MNGC studies and other reports, should provide the Company with a sound foundation of technical and market information to use in the development of cost-effective C&LM programs for its customers.

However, the Company's process for evaluating C&LM options remains incomplete. While it is appropriate for the Company to evaluate C&LM options on the basis of MDPU-approved avoided cost calculations, the Company's current reliance on this single criterion is an inadequate basis for evaluating incremental supply resources.

The Siting Council has previously emphasized the important role that non-price criteria should play in a gas or electric company's supply planning process. <u>1989 Bay State Decision</u>, EFSC 88-13, pp. 46-47; <u>1989 MECo Decision</u>, 18 DOMSC at 357-361, <u>1988 EECo Decision</u>, 18 DOMSC at 119-123.

Boston Gas' original MDPU proposal, in which it developed and proposed a set of non-price criteria for C&LM, is noteworthy in that it demonstrates that the Company is seriously considering the role of non-price criteria in its supply planning process. However, Boston Gas failed to include non-price criteria as part of its C&LM evaluation process in the instant proceeding. This decision is difficult to understand in light of the Company's original proposal to the MDPU and the Company's use of non-price criteria in its evaluation process for traditional supply options (see Section III.C.2.a, above).

While the Company's argument that non-price criteria are difficult to quantify is valid in many cases, these same difficulties exist in quantifying the non-price criteria used by the Company in its evaluation of traditional supply options. In the Siting Council's opinion, while quantification generally is preferable to non-quantification for non-price criteria, difficulty in quantifying a given criterion is not an acceptable reason for ignoring an important criterion altogether. By failing to consider criteria which may be difficult to quantify, the Company is effectively assigning a value of zero to factors which potentially should be highly relevant in its decisionmaking process. The Siting Council sees no reason why the Company should not, in the absence of a tried and true means to quantify certain non-price criteria, perform the same type of qualitative evaluation of non-price criteria for C&LM options as the Company now performs for traditional supply options.

Accordingly, the Siting Council makes no finding in this proceeding regarding Boston Gas' supply planning process for C&LM resources. The Siting Council ORDERS Boston Gas in its next filing: (1) to develop an appropriate set of non-price criteria for C&LM as well as for traditional supply options;[32] (2) to attempt to quantify these criteria to the extent possible; and (3) to present support for the evaluation of those non-price criteria which are not readily subject to quantification.

d. Consideration of All Resources on an Equal Footing

The Siting Council consistently has held that in order for a gas company's supply planning process to minimize cost, that process must adequately consider alternative resource additions, including C&LM options, on an equal basis. 1989 Bay State Decision, EFSC 88-13, p. 51; 1989 Fitchburg Decision, EFSC 86-11A, p. 51; 1988 ComGas Decision, 17 DOMSC at 138-139; 1987 Bay State Decision, 16 DOMSC at 85; 1987 Berkshire Decision, 16 DOMSC at 85; 1987 Boston Gas Decision, 16 DOMSC at

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[32] The Siting Council notes that the non-price criteria selected by the Company for the evaluation of C&LM programs may or may not be identical to those selected for traditional supply options. The Company should provide a justification for its choice of non-price criteria in either case and also should provide a justification for any differences in the evaluation criteria used for C&LM and traditional supply options.

252; <u>1986 Fall River Decision</u>, 15 DOMSC at 115.

Boston Gas has demonstrated considerable progress in developing its supply planning processes for pipeline and supplemental supplies, spot gas supplies, and C&LM resources[33] (see Sections III.2.a,b, and c, above). However, while the Company has established that its supply planning process enables the Company to evaluate the costs of supply and C&LM resources on an equivalent basis, it currently does not evaluate the non-price characteristics of these resources on an equivalent basis. In addition, the Company's supply planning process does not ensure that the Company will compare a reasonable range of supply options at times when resource decisions are made. Without such a comparison, the Company cannot establish that it is truly treating all resource options on an equal footing.

At the same time, the Siting Council acknowledges the significant progress that Boston Gas has made towards integrating C&LM resources into its overall supply planning process. The Company's C&LM Plan is a significant initial step forward for gas utility C&LM development in the Commonwealth. However, the Company must consider the non-price attributes of C&LM resources, as it currently considers the non-price attributes of traditional supply options, in order to acheive a fully integrated supply planning process.

In summary, the Company has made progress in terms of considering all resource options on an equal basis but is deficient in its treatment of non-price criteria for C&LM resources. Consequently, the Siting Council makes no finding here as to whether the Company's supply planning process ensures the treatment of all supply options on an equal footing.

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[33] The Siting Council concludes that its equal footing requirements are not applicable to spot gas since the short-term, interruptible nature of spot gas supplies are quite different than those of firm pipeline, supplemental, or C&LM resources, which are part of the Company's long-term supply plan.

3. Conclusions on the Supply Planning Process

In the 1987 Boston Gas Decision, the Siting Council found that Boston Gas "failed to establish that it has a planning process that ensures that its assumptions, methodologies and decisions result in a least-cost supply plan" (16 DOMSC at 248). In that decision, the Siting Council expressed concern regarding the Company's failure to provide adequate documentation for its assertions that its planning process results in a least-cost supply. Id., at 247-248

In the instant proceeding, the Siting Council has found that Boston Gas' processes for identifying and evaluating firm pipeline and supplemental gas supplies and spot gas supplies are appropriate. The Siting Council made no finding regarding the Company's process for identifying and evaluating C&LM resources. In addition, the Siting Council made no finding as to whether the Company's supply planning process ensures the treatment of all supply options on an equal footing.

In general, the Company has demonstrated that it has made significant progress in developing and documenting an appropriate supply planning process. However, this process remains incomplete because the Company does not currently consider non-price criteria in its evaluation of C&LM options. Because of this deficiency, Boston Gas cannot adequately compare a particular C&LM resource with other C&LM resources nor can it adequately compare C&LM resources with traditional supply resources.

Despite this significant problem, the Siting Council finds that, on balance, 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 is minimally sufficient to enable it to make least-cost supply decisions.

The Siting Council's enabling statute also directs it to balance economic considerations with environmental impacts to ensure that the Commonwealth has a necessary supply of energy.

G.L. c. 164, sec. 69H. In the future, the Siting Council directs Boston Gas to include an adequate consideration of the environmental impacts of resource options in its supply planning process.

D. Base Case Supply Plan

In this section, the Siting Council reviews the Company's supply plan and identifies elements which represent potential contingencies affecting the adequacy of supply, or potentially impact the cost of the supply plan. The Siting Council then reviews the adequacy of the Company's supply plan in Section III.E, below, and evaluates whether the Company's planned supplies contribute to a least-cost supply plan in Section III.F, below.

1. Pipeline Gas and Storage Services

Boston Gas currently receives deliveries of pipeline gas and storage return gas from Algonquin and Tennessee (Exhs. BGC-1, Sec. 1, pp. 26-29, Table G-24). Algonquin delivers firm gas under rates F-1, F-2, F-3, and WS-1 (id.). Boston Gas stated that on November 14, 1988, it was notified by Algonquin that service under rate WS-1 would be terminated on November 16, 1989 (Exh. HO-SP-8). Algonquin notified Boston Gas of its intent to terminate service under rate WS-1 as a result of Texas Eastern Transmission Corporation's ("Texas Eastern") notification to Algonquin of its intent to abandon this service (id.). Abandonment of this service requires authorization from the Federal Energy Regulatory Commission ("FERC") (id.). The Company indicated that Texas Eastern has applied to FERC for authorization to abandon WS-1 service (Exh. HO-SP-63).[34] The Company also indicated that in the same application, Texas Eastern has filed for authorization to provide Algonquin with storage service under rate SS-1 and

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[34] FERC has docketed the application as CP90-186-000 (Exh. HO-SP-63). As of the close of this proceeding, FERC has not reached a decision on that application.

sales service under rate SCQ (id.). Boston Gas stated that Texas Eastern proposed these new services to replace the current WS-1 service (id.).

In addition, Algonquin provides Boston Gas with storage service and return transportation under rates STB and SS-III (Exh. BGC-1, Sec. 1, pp. 27-28). Under rate STB, Algonquin provides firm return transportation during the period November 1 through March 31 (id.). For the same time period, Algonquin provides firm return transportation under rate SS-III within the combined F-1/WS-1 maximum daily quantity ("MDQ") of 175.3 MMcf (id.). That is, if on any day during the period November 1 through March 31 Boston Gas does not take all of the combined F-1/WS-1 MDQ, then Algonguin will provide firm return transportation under rate SS-III up to this combined amount. For volumes above the combined F-1/WS-1 MDQ, Algonquin provides interruptible return transportation (id., p. 28).

Finally, Algonquin delivers interruptible gas to Boston Gas under rate I-1 (id., p. 27). Boston Gas stated that it does not rely on this gas to meet its firm sendout or storage refill requirements, but uses this gas during the non-heating season to meet its interruptible sendout requirements (id.).

Tennessee delivers firm gas under rate CD-6 (id., pp. 28-29). Tennessee also provides Boston Gas with firm transportation of gas volumes from Boundary under rate CGT as part of the Boundary Phase II Project (id., p. 32; Exhs. HO-SP-7, updated Table G-24, HO-SP-7N, HO-SP-7S). Boston Gas began to receive deliveries of this gas on January 15, 1988 (Exh. BGC-1, Sec. 1, p. 32). In addition, Tennessee provides Boston Gas with three storage services. Storage is provided by: (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 and ISST-NE (interruptible); and (3) Penn York Energy Corporation ("Penn York") under rate SS-2, with associated return transportation via Tennessee under rates FSST-NE and ISST-NE (id., pp. 29, 32-33; Exhs. HO-SP-7, Updated Table G-24, HO-SP-7I through HO-SP-7M, HO-SP-7O - HO-SP-7Q).

The Company stated that it is planning for additional firm pipeline gas supplies during the forecast period. This supply will consist of a purchase from Tennessee of an additional 39.6 MMcf per day, and a purchase from PennEast Gas Services Company ("PennEast CDS") of an additional 29 MMcf per day (Exhs. HO-SP-67, Table G-23, BGC-2, p. 5, BGC-3). The Company also stated that it is planning on a purchase from ANE of an additional 17.1 MMcf per day and from Esso Resources Canada Limited ("Esso") of an additional 35 MMcf per day (Exh. HO-SP-64).[35]

The additional purchase from Tennessee will be provided under rate CD-6 and is part of Tennessee's NOREX pipeline expansion project in New England (id.; Exh. BGC-2, p. 5).[36] Boston Gas plans to use the NOREX project to increase deliveries of natural gas into the northern part of the its service territory (Exh. BGC-2, p. 6). Boston Gas indicated that it had expected to receive full deliveries of NOREX volumes beginning November 1, 1989 (id.; Exh. HO-SP-10). Boston Gas stated that because Tennessee experienced delays in obtaining necessary approvals and permits, it began to receive 20.7 MMcf per day of the NOREX volumes, or approximately 52 percent of the total NOREX contract volume, beginning November

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[35] On July 24, 1987, FERC, in Docket CP87-451-000 et. al., issued a notice inviting applications to provide new gas service to the Northeast U.S. (Exh. BGC-2, p. 4). This proceeding became known as the "Open Season" proceeding. In response to its notice, FERC received 39 separate applications including applications for the NOREX and PennEast CDS projects, as well as for pipeline capacity to transport the ANE and Esso volumes (id., pp. 4-5).

[36] Tennessee's NOREX pipeline expansion project will enable Tennessee to make additional deliveries to Boston Gas and nine other New England customers as well (Exh. BGC-2, pp. 6-7).

16, 1989 (Exh. HO-SP-62).[37] The Company stated that it expects full contractual deliveries beginning November 1, 1990 (id.).

The Siting Council evaluates whether the addition of the NOREX volumes contributes to a least-cost supply plan (see Section III.F.2.a, below).

The Company stated that the PennEast CDS project formally began in 1987, as a partnership of Texas Eastern and Consolidated Natural Gas Company designed to bring existing supplies not currently being utilized in other regions of the country into the Northeast (Exh. BGC-75, p. 9). The Company indicated that the additional purchase from PennEast will be provided under rate CDS and delivered via Algonquin under rates PFT-1 and T-3 (Exhs. BGC-2, p. 5, BGC-3). The Company stated that the PennEast CDS project requires some new facilities to be constructed on both the Texas Eastern and Consolidated systems, and some reinforcements, looping, and increased compression on the Algonquin system (Exh. BGC-75, p. 9). The Company also stated that in order to receive the PennEast CDS volumes, the PennEast CDS project must be certified by FERC (id., pp. 9-10). Boston Gas expects full deliveries of the PennEast CDS volumes beginning November 1990 (Tr. 6, p. 65; Exh. HO-SP-51).

The Company's base case supply plan includes the new increment of pipeline supply from the PennEast CDS project (Exh. HO-SP-67, Table G-22D, G-22N, G-23). The Siting Council notes that a number of milestones not under the Company's control must be achieved before this new pipeline supply is

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37/ The Company stated that Tennessee was not able to deliver full contractual volumes by November 1, 1989 due primarily to a delay in obtaining a certificate from FERC (Exh. HO-SP-62). The Company stated that this delay prevented Tennessee from gaining right-of-way access to allow construction on several segments in Massachusetts (id.). The Company also stated that a delay in obtaining a permit from the Environmental Protection Agency and a building permit from the Town of Burlington contributed to Tennessee's inability to deliver full contractual volumes by November 1, 1989 (id.).

available for use in the Company's system. The Siting Council therefore evaluates the adequacy of the Company's supply plan in the event of further changes or delays in the anticipated volumes. The Siting Council considers the following contingency associated with the Company's planned addition of PennEast CDS volumes: a one-year delay in delivery of the entire 29 MMcf per day to November 1991 (see Sections III.E.1.b and III.E.2.b, below). The Siting Council also evaluates whether the addition of the PennEast CDS volumes contributes to a least-cost supply plan (see Section III.F.2.d, below).

Under the ANE and Esso arrangements, ANE will provide Boston Gas with an additional 17.1 MMcf per day, and Esso will provide the Company with an additional 35 MMcf per day (Exhs. BGC-3, HO-SP-64). The Company provided that the ANE volumes would be delivered to the northern part of its service territory via the Iroquois Gas Transmission System ("Iroquois") and Tennessee pipeline systems (Exhs. HO-SP-13B, HO-SP-64).[37A] Tennessee would deliver the ANE volumes to take stations in Danvers, Reading, and Salem/Beverly (Exh. HO-SP-64).[38] The Company's plans for the transportation of the Esso volumes changed during the course of this proceeding. The Company originally stated that 35 MMcf per day would be delivered to its service territory via the Champlain Pipeline Company ("Champlain") and Algonquin pipeline systems (Exh. HO-SP-13A). The Company stated that, in response to reported difficulties with the Champlain pipeline project

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37A/ Iroquois proposes to construct a new pipeline beginning in Iroquois, Canada at the New York/Canadian border and extending into New York and Connecticut (Exhs. HO-RR-5B, HO-SP-65A). With respect to the ANE volumes as well as the Esso volumes, this gas would be transported through that portion of the proposed Iroquois pipeline extending from Iroquois, Canada to Wright, New York, which would be the Iroquois/Tennessee interconnection point (Exhs. HO-SP-65A, HO-SP-65C).

38/ The Company stated that the Danvers take station would be a new station built by Tennessee (Exh. HO-SP-64).

and as a result of Champlain's inability to provide Boston Gas with adequate assurances that they would be able to transport the designated volumes on a timely and competitive basis, Boston Gas informed Champlain that it was terminating its agreement for the transportation of the Esso volumes (Exh. HO-SP-64).

The Company presented an amended precedent agreement between Boston Gas and Iroquois, dated September 28, 1989, which provides for the transportation of the 35 MMcf per day of Esso volumes through the Iroquois pipeline (Exh. HO-SP-65B).[39] The Company also presented a precedent agreement dated October 11, 1989, between Boston Gas and Tennessee for transportation of 35 MMcf per day from the Iroquois pipeline to the interconnection of Tennessee's and Algonquin's systems in Mendon, Massachusetts and four Tennessee take stations (Exh. HO-SP-65C). This agreement would require the construction of new facilities on Tennessee's system that must be certified by FERC (id.; Exh. HO-SP-64). In addition, the Company presented an amendment to a precedent agreement between Boston Gas and Algonquin, dated September 28, 1989, which reflects the change in Algonquin's receipt point for Esso volumes from W. Medway, Massachusetts, which would have been the Algonquin/Champlain interconnection point, to Mendon, Massachusetts, which is the Algonquin/Tennessee interconnection point (Exh. HO-SP-65A). Further, the Company presented an amendment to the gas sales agreement between Boston Gas and Esso, dated September 28, 1989, which accounts for the change in the delivery point from the Champlain interconnection point with TransCanada Pipelines Limited ("TCPL") in Phillipsburg, Quebec to the Iroquois interconnection point with TCPL in Iroquois, Ontario (Exh. HO-SP-65A).

39/ This agreement states, however, that should such an amendment subject Iroquois to additional comparative hearings at FERC, Iroquois would terminate the agreement (Exh. HO-SP-65B). The agreement further states that such a termination would not effect the 17.1 MMcf per day of ANE volumes originally slated for delivery to the Company (id.).

The Company stated that in order to receive the Esso volumes, Esso must obtain its gas removal permit from the Alberta Energy Resources Conservation Board and its export license from the National Energy Board ("NEB") (Exh. HO-SP-64). The Company also stated that in order to receive the ANE volumes, TCPL must receive approval from the NEB for its 1991-92 facilities application, and TCPL and NOVA (the intra-Provincial pipeline system that connects the fields containing the Esso and ANE reserves with TCPL) must construct specified facilities (id.). In addition, the Company stated that in order to receive both the ANE and Esso volumes, the Iroquois project must be certified by FERC (id.).

The Company stated that it anticipated deliveries of the ANE and Esso volumes commencing by November, 1991 (Exhs. HO-SP-13, HO-SP-51, HO-SP-64). However, although the Company provided that it expects all permits, licenses, and approvals to be obtained in time for the Company to receive the ANE and Esso volumes beginning November 1, 1991 (id.), the Company did not include the ANE and Esso supplies in the base case supply plan due to what the Company described as a potential for delay in obtaining such permits, licenses, and approvals (Exh. HO-SP-67; Tr. 6, p. 74).

The Siting Council evaluates whether the Company properly excluded the ANE and Esso volumes from its base case supply plan and whether these supplies contribute to a least-cost supply plan in Section III.F.2.b, below.

2. Supplemental Supplies and Facilities

a. LNG

Boston Gas operates LNG vaporization and storage facilities at Commercial Point (Dorchester), Lynn, and Salem (Exh. BGC-1, Sec. 1, p. 34). The combined storage capacity of these three facilities is 4,140 MMcf (id.; Exh. HO-SP-22A). The Company stated that the combined vaporization capacity of these facilities for base case planning purposes is 291.4 MMcf per day (id.; Exh. HO-SP-67, Table G-23).[40] This combined LNG vaporization capacity includes 15 MMcf per day at Salem facility, 190 MMcf at Commercial Point, and 86.4 MMcf at Lynn (Exh. HO-SP-22A). The Company also stated that the combined standby capacity of the Salem and Commercial Point facilities, which represents the equivalent of one vaporizer at each of these facilities, is 77.5 MMcf per day (Exh. BGC-1, Sec. 1, p. 34). The Company provided that standby capacity provides the Company with peak day coverage and with capacity in case of equipment malfunction to other vaporizers (id.; Exh. BGC-58, p. 4).[41] The Company's supply plan calls for continued reliance on LNG from storage throughout the forecast period (Exh. HO-67, Tables G-22N, G-22D, G-23).

In Section III.E.4.a, below, the Siting Council considers the Company's compliance with Order Seven from the 1987 Boston Gas Decision which pertains to vaporization capabilities at Commercial Point, Lynn, and Salem.

The Company claimed that it can liquefy at the rate of 6 MMcf per day at Commercial Point, and 7.35 MMcf at Lynn (Exh. BGC-58, p. 14). Boston Gas stated that it assumes that full LNG liquefaction will be available to meet LNG refill requirements on all days that excess pipeline gas is not required for firm sendout (id.). In Section III.E.1.a, below, the Siting Council considers the Company's compliance with Order Two from the 1987 Boston Gas Decision which pertains to liquefaction capabilities at the Commercial Point and Lynn facilities.

At the time of Boston Gas' initial filing in this

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[40] The Company indicated that in 1987 it added a vaporization unit with a vaporization capacity of 65 MMcf per day at Commercial Point (Exh. HO-SP-70). The Company also indicated that it does not project a need for the additonal vaporization unit at Lynn that it planned to install in November 1988 (Exh. BGC-58, p. 21).

[41] In the past decision, the Siting Council found that the Company's operating procedure of providing for standby capacity is reasonable. 1987 Boston Gas Decision, 16 DOMSC at 221.

proceeding, the Company indicated that it was not receiving LNG deliveries from DOMAC (Tr. 1, p. 42; Exh. HO-SP-26).[42] As a result, the Company only included in the base case its vaporization capacity of 66.6 MMcf per day from its remaining storage entitlement amount at DOMAC's LNG facility in Everett, Massachusetts (Exh. BGC-1, Sec. 4, Table G-23). However, the Company stated that on June 14, 1988, Boston Gas and DOMAC entered into a settlement agreement wherein the parties resolved past disputes and agreed to enter into new LNG sales, transportation, and storage services (Exhs. BGC-1, Sec. 1, p. 29, BGC-2, p. 10). Boston Gas also provided that on July 15, 1988, DOMAC filed an application at FERC requesting an order authorizing the restructuring of its LNG sales and services arrangements (Exh. HO-SP-24). On December 16, 1988, FERC issued a certificate of public convenience and necessity authorizing DOMAC's application subject to certain conditions (id; Exh. HO-SP-56A).

Under the restructured sales and services arrangements, the Company and DOMAC entered into a liquid purchase agreement which provides that Boston Gas has the option to purchase 2,000 MMcf of LNG during the period from March 15 through November 15 for a term of ten years, and up to an additional 2,000 MMcf of LNG per year subject to mutually agreeable price, delivery, and quantity terms (Exhs. BGC-2, p. 11, BGC-75, p. 15, HO-SP-70A).[43] In addition, the Company presented a storage agreement between Boston Gas and DOMAC which increased the

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[42] DOMAC's importer affiliate, Distrigas Corporation, had filed for bankruptcy and stopped its deliveries of LNG. See: 1987 Boston Gas Decision, 16 DOMSC at 219. Currently, Distrigas Corporation is the major importer of LNG supplies to the northeastern United States. DOMAC is a major distributor of imported LNG to DDC's in the northeastern United States. For the purposes of this review, the Siting Council's discussions of this LNG supply source will refer to DOMAC but apply to Distrigas Corporation where appropriate.

[43] Late in the proceeding, the Company presented a one-year firm liquid service agreement it executed with DOMAC which provides provides Boston Gas with firm LNG deliveries of 2,000 MMcf over the period from November 1, 1989 to October 31, 1990 (Exh. HO-SP-70E).

Boston Gas' DOMAC storage entitlement from 643 MMcf to 1,000 MMcf, and Boston Gas' DOMAC vaporization entitlement from 66.6 MMcf per day to 100 MMcf per day (Exh. HO-SP-7U; Tr. 1, pp. 38-39). The storage agreement also entitles Boston Gas to take up to 37 truckloads of liquid LNG from its storage entitlement at Everett (Exhs. HO-SP-7U, HO-SP-70A). Finally, the Company and DOMAC entered into agreements for boil-off purchases and transportation services for DOMAC's customers (Exhs. BGC-2, p. 11, BGC-75, p. 15, HO-SP-7T, HO-SP-70C).

As a result of these agreements, the Company filed revised tables which include DOMAC LNG in its base case supply plan for its normal and design year heating and non-heating seasons as well as in its base case supply plan for its design day (Exh. HO-SP-67, Tables G-22N, G-22D, and G-23). The Company provided, however, that it does not rely on DOMAC deliveries to meet design year heating season requirements (Tr. 5, pp. 52-53). Rather, the Company stated that in planning for heating season requirements, it only relies on vaporization out of its existing storage entitlement at the DOMAC Everett facility (id.; Exh. HO-SP-67, Table G-22D, p. 1).

The Siting Council evaluates whether the new Boston Gas contracts with DOMAC contribute to a least-cost supply plan (see Section III.F.2.d, below).

The Company stated that for design day operation it also has two small LNG vaporization facilities available at Leominster and Webster (Exh. BGC-1, Sec. 1, p. 34). The combined vaporization capacity of these facilities is 4.8 MMcf per day (id.). In addition, the Company stated that it retains rights to store 400 MMcf of LNG at Algonquin's LNG facility in Providence, Rhode Island (id., p. 35; Tr. 6, p. 81), but noted that the storage agreement terminates on May 31, 1992 (Exh. HO-SP-35). The Company stated that, while it expects that Algonquin would be willing to extend the existing arrangement under similar terms and conditions (id.), the increase in its storage entitlement at the DOMAC Everett facility could result in the termination of Algonquin storage service because this service may no longer be needed (Exh. HO-SP-23).

The Company also included anticipated spot purchases of DOMAC LNG in its base case supply plan for its design year non-heating season (Exh. HO-SP-67, Table G-22D, p. 2; Tr. 5, p. 118).[44] Boston Gas provided that it reviews it supply requirements over the time period between arrivals of LNG shipments to determine whether spot purchases from DOMAC are economic (Tr. 5, p. 118). In general, the Company indicated that it intends to take advantage of spot purchases as long as those purchases fit with the Company's least-cost purchasing practices (Exhs. HO-SP-17, HO-SP-18).

b. Propane

Boston Gas stated that it contracts for propane from Sea-3, Inc. ("Sea-3"), which maintains a propane terminal in Newington, New Hampshire (Exh. BGC-69). The Company's agreement with Sea-3 extends for three years from May 1, 1988 through April 30, 1991, and gives the Company the option to purchase propane for each year within that period (id.). The Company indicated that the contract provides it with the option to purchase up to 35 million gallons with a maximum of 60 daily truckloads over the period from May 1, 1988 through April 30, 1989; up to 25 million gallons with a maximum of 50 daily truckloads over the period from May 1, 1989 through April 30, 1990; and up to 15 million gallons with a maximum of 40 daily truckloads over the period from May 1, 1990 through April 30, 1991 (id.). The Company stated that the propane is transported to the Company's propane storage and production facilities located throughout it service territory (Exhs. HO-SP-69A, HO-SP-69B).

The Company presented propane transport agreements between Boston Gas and Transgas Inc. ("Transgas") of Lowell, Massachusetts for 1988-89 and 1989-90 (id.). The agreement for

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[44] Late in the proceeding, the Company indicated that it had contracted with DOMAC several times for spot purchases of LNG under rate ISS during late 1988 and throughout 1989 (Exhs. HO-SP-70, HO-SP-70F).

1988-89 provides that Transgas will make available, for the exclusive use of the Company, 20 propane trailer units, drivers, tractors, and other services with a delivery capacity of up to 60 loads per day between Sea-3's propane terminal in Newington and the Company's propane facility in Everett (Exh. HO-SP-69A). The agreement also provides that Boston Gas can request deliveries over and above 60 truckloads per day which Transgas will provide on a best efforts basis (id.). The agreement for 1989-90 provides that Transgas will make available for the exclusive use of the Company seven propane trailer units, drivers, tractors, and other services with a delivery capacity of up to 21 loads per day between Sea-3's propane terminal in Newington and the Company's propane facility in Everett (Exh. HO-SP-69A). The agreement also provides that Boston Gas can request deliveries over and above 21 truckloads per day which Transgas will provide on a best efforts basis (id.). The Company stated that each propane trailer can carry approximately 9,500 gallons of propane (Exh. BGC-58, p. 18).

The Company owns ten propane facilities which have a combined storage capacity of 167.6 MMcf per day and a combined vaporization capacity of 107.3 MMcf per day (Exh. BGC-1, Sec. 3, Table G-14).[45] The largest of these propane facilities is the Company's propane facility in Everett (id.). This facility has a storage capacity of 65.6 MMcf and a vaporization capacity of 40 MMcf (id.). In addition, the Company owns a SNG production facility in Everett (Exh. BGC-1, Sec. 1, p. 33). The feedstock for the SNG facility is propane, which the Company indicated would be provided by Sea-3 when required (id.). The SNG production facility has a vaporization capacity of 40 MMcf per day (id.). The Company stated that it normally uses the propane facility at Everett as a backup to its SNG production facility at Everett (id.).

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[45] The Company stated that in August, 1988 it retired and dismantled its West Concord propane facility (Exh. HO-SP-22). See Section I.A, above, for a listing of the Company's propane facilities.

The Company's base case supply plan calls for decreased reliance on propane for the normal and design years throughout the forecast period (Exh. HO-SP-67, Tables G-22N, G-22D, G-23). In fact, except for the 1989-90 heating season, the Company does not expect to rely on propane to meet its design heating season requirements during the forecast period due to the resumption of DOMAC LNG deliveries, expected receipt of full NOREX volumes, and anticipated deliveries of PennEast CDS volumes (Tr. 5, p. 42; Exh. HO-SP-67, Table G-22D).

In Section III.E.1, below, the Siting Council considers the Company's compliance with Orders Three, Four, and Five from the 1987 Boston Gas Decision which pertain to propane use.

3. Conservation and Load Management

The Company did not include any energy savings from specific C&LM programs as supply resources in its base case supply plan (Exh. HO-SP-67, Table G-22D, G-22N, G-23). The Company stated that it is in the early stages of identifying and evaluating specific C&LM programs (Exhs. HO-SP-37, HO-SP-60). The Company stated that it will include the impacts of specific C&LM programs in its sendout forecast in the future (Tr. 3, p. 45).

The Company stated that it has identified and is beginning to implement a program for public housing authorities in its service teritory ("PHA program") (Exh. BGC-21, pp. 10-11; Tr. 3, pp. 40-41). The Siting Council evaluates whether the PHA program contributes to a least-cost supply plan in Section III.F.2.e, below.

E. 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 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 Year and Design Year Adequacy

a. Compliance with Orders Two, Three, Four and Five

In the 1987 Boston Gas Decision, the Siting Council evaluated the Company's claimed liquefaction capability of 6 MMcf per day at Commercial Point and 7.35 MMcf per day at Lynn and the Company's ability to meet its design year LNG refill requirements at those liquefaction levels. <u>1987 Boston Gas Decision</u>, 16 DOMSC at 225-231. The Siting Council determined that, based on the recent historical liquefaction performance at the Commercial Point and Lynn facilities, the Company had not established that its liquefaction capability was 7.35 MMcf per day at Commercial Point and 6.0 MMcf per day at Lynn. <u>Id.</u>, at 229. The Siting Council also determined that at the claimed liquefaction capabilities of these facilities, the Company could not meet its 1986-87 design year LNG refill requirments. <u>Id.</u>, at 230.[46] Consequently, the Siting Council found that Boston Gas had not demonstrated its ability to refill its LNG storage facilities in all design years during the forecast period (<u>Id.</u>, at 230), and ordered Boston Gas to include in its next forecast filing:

> 2. (1) a reevaluation of its Commercial Point and Lynn liquefaction capabilities that adequately considers historical liquefaction experience; (2) a demonstration that its reevaluated liquefaction capabilities are sufficient to meet forecasted liquefaction requirements in all forecast years; and (3) if the Company cannot demonstrate such liquefaction capability, a proposed plan for securing adequate LNG refill capability and a schedule for implementing that plan. <u>Id.</u>, at 230, 270.

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[46] The Siting Council found that the Company's 1986-87 design year plan would provide excess pipeline capacity for liquefaction on nine days in the heating season and 206 days in the non-heating season for a total of 215 days. <u>1987 Boston Gas Decision</u>, 16 DOMSC at 227.

In response to this Order, the Company asserted that it in fact could liquefy at the claimed capabilities of 6 MMcf per day at Commercial Point and 7.35 MMcf per day at Lynn (Exh. BGC-58, p. 14). The Company indicated that since late 1985, when it became necessary to operate the liquefaction equipment at Commercial Point and Lynn due to the termination of DOMAC LNG deliveries, it has experienced liquefaction downtime mainly because of equipment failures (Exh. HO-SP-27).[47] The Company provided, however, that in 1987 and 1988, it made major changes and repairs to the liquefaction equipment at the Commercial Point and Lynn LNG facilities (Exhs. BGC-58, p. 13, HO-SP-27, HO-SP-28; Tr. 5, pp. 147-150).

The Company stated that since heating season temperatures have been warmer than design since 1985, and because of the resumption of DOMAC LNG deliveries, which lessens the need for liquefaction during the heating season and allows the Company to truck DOMAC LNG to refill its LNG storage facilities during the summer, the Company has not had the need to liquefy at the claimed capabilities for extended time periods (Exhs. BGC-58, p. 13, HO-SP-32, HO-RR-18). The Company asserted, however, that during the period from April 1987 to March 1988, it was able to liquefy for 165 days at Commerical Point and 83 days at Lynn, and that during this time period, liquefaction exceeded 6 MMcf per day at Commercial Point on 94 days and exceeded 7.35 MMcf per day at Lynn on 63 days (Exhs. BGC-65, HO-SP-29).

47/ The Company provided that the liquefaction facility at Commercial Point became operable in 1969 and from that date to 1976, liquefaction occurred on a regular basis (Exh. HO-SP-27). In 1976, DOMAC LNG deliveries began and during the time period from 1976 to 1985, the Company met most of its LNG refill requirements with DOMAC LNG and, as a result, liquefaction operations consisted primarily of test runs (*id.*). With the termination of DOMAC LNG deliveries in 1985, liquefaction again occurred on a regular basis from 1985 to 1987 (*id.*). The Company provided that the same situation applied to the Lynn facility except that the liquefaction facility at Lynn became operable in 1972 (*id.*).

In regard to the third part of the Order, the Company asserted that it could adequately meet its design year LNG refill requirement with DOMAC LNG and liquefaction at Commercial Point (Exhs. BGC-58, p. 15, HO-RR-18; Tr. 5, pp. 124-127). The Company indicated that under this plan, liquefaction at Lynn would serve as a backup (Tr. 5, p. 125). The Company indicated that under its new service agreement with DOMAC, it has the right to purchase up to 2,000 MMcf of LNG annually for a period of 10 years, and that these purchases are made during the summer to meet its LNG refill requirements (Exh. HO-SP-70A). The Company also asserted that the need to liquefy to meet its LNG refill requirements would decrease with the use of additional pipeline supplies during the heating season because new pipeline supplies will alleviate some of the need for supplemental supplies during the design year heating season (Tr. 5, pp. 130-132; Tr. 6, pp. 4-5). Finally, the Company asserted that the liquefaction could extend into the heating season by using propane on marginally cold days and releasing pipeline gas for liquefaction (Exhs. BGC-58, p. 15, BGC-67, BGC-68).

Based on the record, the Siting Council finds that the Company has not established that it can operate its liquefaction facilities at the claimed capabilities and meet its LNG refill requirements during a design year with or at levels above its claimed liquefaction capabilities. While the Company has presented evidence showing that the Company liquefied for a number of days at Commercial Point and Lynn and at rates above the claimed liquefaction capability on some of those days, this evidence also shows that the liquefaction equipment at these facilities was down for extended periods of time for repairs. The Siting Council recognizes that the Company has taken measures to improve its liquefaction capabilities at Commercial Point and Lynn through these repairs and major changes. However, evidence of historical experience of the liquefaction equipment operating at or above the claimed liquefaction capabilities over extended time periods, within a year and as well as over a number of years, is necessary to establish that the reliability of the Company's liquefaction facilities. The record here does not include such evidence.

The Siting Council recognizes that the Company's supply portfolio has changed in recent years. In particular, DOMAC LNG deliveries resumed in 1988, NOREX volumes arrived in 1989 with additional volumes expected in 1990, PennEast CDS volumes are expected in 1990, and firm propane volumes are under contract through 1991. The combination of these supplies will significantly minimize the need for liquefaction in meeting design year LNG refill requirements. Thus, while the Company has not presented a formal plan for securing adequate LNG refill capability and a schedule for implementing that plan as required by the Order, the Company has shown that with its current and anticipated supply sources it can adequately meet its LNG refill requirements for design years throughout the forecast period.

Accordingly, the Siting Council finds that the Company minimally has complied with Order Two from the 1987 Boston Gas Decision. We note, however, that if the Company's supply portfolio should change in the future and, as a result, increased reliance is placed on the Company's liquefaction capabilities to meet its LNG refill requirements for the design year, then the Company should be prepared to present a full analysis to the Siting Council demonstrating the Company'a ability to operate its liquefaction facilities at a level that would ensure that the Company can meet its LNG refill requirements for a design year.

With respect to the Company's use of propane, the Siting Council, in the <u>1987 Boston Gas Decision</u>, 16 DOMSC at 270-271, ordered the the Company to include in its next forecast filing:

> 3. a complete argument demonstrating its ability, on a daily basis during the design year in that filing that requires the most propane, to contract for propane supplies, to receive such supplies from its supplier, to transport those supplies to the necessary propane dispatch facilities, to dispatch the propane, and to maintain adequate propane inventories;

> 4. (1) an estimation and detailed analysis of its maximum ability to use propane given all the procurement, storage, and dispatch constraints, (2) an identification of the critical factor(s) determining that maximum amount, and (3) propane dispatch sensitivity analyses for a reasonable range of estimates for such critical factors; and
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> 5. a justification for any terminalling rights at Sea-3's Newington, NH propane terminal above the Company's maximum ability to use propane as a supply.

In its initial filing, the Company forecasted that the most propane it would use during any one year in the design year forecast would be 3,345 MMcf or approximately 36 million gallons of propane (Exh. BGC-1, Sec. 4, Table G-22D, p. 1; Tr. 6, p. 10). The Company prepared its response to Orders Three and Four based on the above amounts (Exhs. BGC-58, pp. 16-20, BGC-68). In its latest revised supply plan, the Company forecasted that the most propane it would use in the design year heating season forecast would be 1,182 MMcf, or approximately 12.9 million gallons, in the 1989-90 heating season (Exh. HO-SP-67, Table G-22D, p. 1).[48] The Company did not include the use of propane in any other year of the design year heating season forecast (id.).

Since the Company has included propane in the revised supply plan, and has a contract with Sea-3 that allows it to take up to to 25 million gallons of propane in 1989-90 and 15 million gallons of propane in 1990-91, it is necessary to review the Company's responses to Orders Three and Four in order to determine if the Company can receive, transport, dispatch, store, and maintain adequate inventory levels. In response to these Orders, the Company provided documentation

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48/ As stated previously, the Company first presented a revised supply plan that did not include the use of propane during the design year heating season for all years of the forecast (Exh. BGC-76, Table G-22D, p. 1). After the Company determined that full NOREX volumes would not be available in 1989-90, the Company presented another revised supply plan that included propane use during the 1989-90 design year heating season (Exh. HO-SP-67, Table G-22D, p. 1).

and analysis demonstrating its ability to receive, transport, dispatch, store, and maintain adequate propane inventories (Exhs. BGC-58, pp. 16-21, BGC-68, BGC-69, HO-SP-69A, HO-SP-69B; Tr. 6, pp. 10-11). The Company also identified the critical factors impacting maximum propane use and presented sensitivity analyses for propane dispatch (Exh. BGC-68; Tr. 6, pp. 11-13). Accordingly, the Siting Council finds that the Company has complied with Orders Three and Four from the 1987 Boston Gas Decision.

In response to Order Five, the Company asserted that the amount of propane it has the right to take pursuant to its contract with Sea-3 does not exceed its ability to use that propane (Exh. HO-58, p. 21; Tr. 6, p. 18). The Siting Council finds that the Company has shown the ability to dispatch 35 million gallons of propane annually, the most propane it could receive under its current contract with Sea-3 (Tr. 6, p. 18; Exh. BGC-68). Further, we note that the Company's terminalling rights have been reduced in accordance with the Company's estimation of its design year propane requirements (Exhs. BGC-69, HO-SP-67, Table G-22D). Accordingly, the Siting Council finds that the Company has complied with Order Five from the 1987 Boston Gas Decision.

b. <u>Base Case Analysis</u>

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 customers. 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.

In its initial filing, the Company presented its supply plans for meeting its forecasted normal year and design year sendout requirements throughout the forecast period (Exh. BGC-1, Sec. 4, Tables G-22N, G-22D). To reflect the resumption of DOMAC LNG deliveries, the Company presented revised supply tables during the course of the proceedings (Exh. BGC-76, Tables G-22N, G-22D). Later, to reflect the change in the delivery of NOREX volumes for 1989-90, the Company presented a second set of revised supply tables (Exh. HO-SP-67, Tables G-22N, G-22D). The Company's latest revised supply plan includes anticipated interruptible sales and liquefaction refill requirements during both normal and design years (id.).

The Company stated that the resumption of DOMAC LNG deliveries allowed it to reduce firm propane purchases during the design year (Exh. BGC-75, p. 3; Tr. 5, p. 42). In fact, in its first revised supply plan, the Company included no firm propane purchases in the design heating and non-heating seasons in any years of the forecast (Exh. BGC-76, Table G-22D). However, in its second revised supply plan the Company included firm propane purchases for the 1989-90 design year heating season to account for the less than expected NOREX deliveries for that heating season (Exh. HO-SP-67, Table G-22D, p. 1).

The Company's second revised supply plan includes full NOREX and PennEast CDS deliveries beginning in 1990-91 and continuing for all years of the forecast for both the design and normal years (id., Table G-22D, Table G-22N). The Siting Council notes that over this same time period the Company has projected a decrease in the use of LNG from its own storage facilities for the design year and normal year heating seasons (id., Table G-22D, p. 1, Table G-22N, p. 1). Further, the Siting Council notes that the Company has available to it LNG in storage in excess of planned use during both normal and design year heating seasons for all years of the forecast (id.).

As noted previously, the Company's base case supply plan does not include the ANE and Esso volumes and any anticipated gas savings due to specific C&LM programs (Exh. HO-SP-67, Table G-22D, G-22N). The Siting Council also notes that the Company has the ability to reduce or fully eliminate interruptible sales as needed to meet its firm sendout requirement.

The Siting Council notes that the Company's supply plan has changed during the course of the proceeding. The Company, however, has provided the Siting Council with the basic elements of its plan, as well as sufficient information to establish that its base case plan ensures that the Company's firm sendout requirements will be met under normal and design conditions throughout the forecast period.

Accordingly, the Siting Council finds that the Company has established that its normal year and design year base case supply plans are adequate to meet the Company's forecasted firm sendout requirements and storage refill requirements throughout the forecast period.

The Company's second revised design year base case supply plan is summarized in Tables 2 and 3.

c. Contingency Analysis

As described above, the Company's second revised normal year and design year base case supply plan includes the PennEast CDS project, which is not yet in place and which requires both permitting and construction activities outside the Company's control (see Section III.D.1, above). The Siting Council therefore reviews the adequacy of the Company's supply plan in the event that the following contingency occurs: a one-year delay in delivery of the entire 29 MMcf per day to November 1991.

Boston Gas' second revised supply plan calls for an in-service date of November 1990 for the PennEast CDS project. In the event that delivery of the 29 MMcf of supplies associated with the project is delayed until November 1991, and if all other resources remain available to the Company, the Company would experience a resource deficiency in meeting forecasted firm sendout in the 1990-91 design year heating season of approximately 2,604 MMcf. See Table 4.

In the event of such a delay, the Company asserted that a significant portion of the PennEast CDS volumes would be replaced by propane (Tr. 6, p. 76). The Company indicated that for the 1990-91 design year, it has the right to take up to 15 million gallons of propane from its Sea-3 contract (Exh. BGC-70). The Company also asserted that the remaining block of PennEast CDS volumes would be made up with the firm utilization of contract gas, increased LNG utililization, and possibly "a certain amount of storage return on a best efforts basis" (id., pp. 76-78). Finally, the Company asserted that it would evaluate its planned load additions under such circumstances (id., p. 75).

The Siting Council finds that an action plan involving a combination of firm propane purchases, increased utilization of the Company's LNG facilities, and the utilization of firm contract gas would allow the Company to meet the deficiency.

Accordingly, the Siting Council finds that Boston Gas has an action plan which would allow it to meet the resource deficiency during the 1990-91 design year in the event of a one year delay in the PennEast CDS project and, therefore, has adequate resources to meet forecasted firm sendout requirements in the event that such a contingency occurs.

2. Design Day Adequacy

a. Base Case Analysis

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.

Boston Gas presented its design day base case supply plan in support of its assertion that it has adequate resources to meet forecasted firm design day sendout requirements throughout the forecast period (Exhs. HO-SP-67, Table G-23, Boston Gas Brief, p. 16). The plan was revised twice, as noted previously, during the course of the proceeding to reflect increased volumes of DOMAC LNG and the delayed delivery date of full pipeline supplies from the NOREX project. The second revised design day base case supply plan indicates that the Company has adequate resources to meet its forecasted firm design day sendout requirements throughout the forecast period. This plan includes volumes respresenting the Company's increased vaporization capacity at DOMAC's LNG facility in Everett in addition to planned new pipeline supplies (see Sections III.D.1 and III.D.2.a, above). As described above, the Company's second revised design day base case supply plan does not include the ANE and Esso volumes and anticipated gas savings from C&LM programs. The Company stated that it maintains standby capacity at: (1) the Commercial Point and Lynn LNG facilities; (2) the propane facility at Everett; and (3) the vaporization units in Leominister and Webster; to meet design day requirements if necessary (Exh. BGC-1, Sec. 1, pp. 33-34).

Accordingly, the Siting Council finds that Boston Gas has established that its base case design day supply plan is adequate to meet forecasted firm design day sendout requirements in all years of the forecast period.

The Company's second revised design day base case supply plan is summarized in Table 5.

b. Contingency Analysis

In the event of a one-year delay in the PennEast CDS project, the Company would not be subject to a design day resource deficiency (see Table 6).

Accordingly, the Siting Council finds that the Company's design day base case supply plan is adequate to meet forecasted firm sendout requirements in the event of a one-year delay in the PennEast CDS project.

3. Cold-Snap Adequacy

In its last decision, the Siting Council ordered Boston Gas to submit an updated cold-snap analysis as part of its next filing. 1987 Boston Gas Decision, 16 DOMSC at 242, 271. The Siting Council has defined a cold-snap as a prolonged series of days at or near design conditions. 1989 Bay State Decision, EFSC 89-13, p. 75; 1989 Fitchburg Decision, EFSC 86-11(A), p. 48; 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. 1989 Bay State Decision, EFSC 89-13, p. 75; 1989 Fitchburg Decision, EFSC 86-11(A), p. 48; 1988 ComGas Decision, 17 DOMSC at 137; 1987 Bay State Decision, 16 DOMSC at 47; 1987 Berkshire Decision, 16 DOMSC at 79; 1986 Fitchburg Decision, 15 DOMSC at 58, 61.

As its cold snap analysis, the Company presented an analysis of its preparedness during 1988-89 to meet a DD weather pattern actually experienced during the month of February, 1979 (Exh. BGC-74). In that month, the Company experienced a DD pattern during the period from February 9 through February 18 in which more than 50 DD occurred each day for ten straight days (id.). The Company stated that the total number of DD for this period was 555, which compares with 476 DD for the coldest ten-day period in the Company's design year DD pattern (id., Exh. BGC-67).

In its analysis, the Company assumed that normal weather would be experienced up to January 31, that LNG storage inventories on February 1 would be approximately 1,000 MMcf below capacity, and that propane would be dispatched during the first week of the month to husband LNG inventories for use later in the month (Exh. BGC-74; Tr. 5, pp. 67, 73). The analysis indicated that during the period from February 9 through February 18, the Company would dispatch all of its contracted pipeline deliveries and supply the remaining requirements with LNG (Exh. BGC-74).

The Company asserted that it would be able to meet its cold-snap standard during any part of the heating season, stating that under its design forward planning standard, it plans on meeting severely cold weather during the earlier part of the heating season (Tr. 5, pp. 59-61).

In the instant proceeding, the Company has responded to the Siting Council's order and presented an updated analysis of its cold-snap plan. Thus, the Siting Council finds that the

Company has complied with Order Six of the previous decision. The Siting Council also finds that the Company's choice of a cold-snap standard based upon an actual period of extreme weather is appropriate for a company of its size and resources. Further, the Siting Council finds that the Company has established that it has an adequate supply to meet its firm sendout requirements in the event of a cold-snap during the second year of the forecast period.

Accordingly, the Siting Council finds that Boston Gas has established that it has adequate resources to meet its firm sendout requirements under cold-snap conditions during the second year of the forecast period. To assure the Company's continuing ability to meet requirements in the event of a cold snap, the Siting Council ORDERS Boston Gas to submit an updated cold snap analysis in its next forecast filing.

4. Distribution System Adequacy

In the last decision, the Siting Council evaluated the adequacy of the Company's distribution system. 1987 Boston Gas Decision, 16 DOMSC at 254-268. In particular, the Siting Council evaluated issues involving the maximum allowable operating pressure ("MAOP") in the Company's Central District,[49] and the Company's use of a 65 DD design day standard for its distribution system planning instead of the 73 DD design day standard it uses for sendout forecasting and supply planning purposes. Id. Here, the Siting Council reviews the Company's response to specific Orders from the 1987 Boston Gas Decision relating to these issues.

a. Compliance with Order Seven

In the last decision, the Siting Council was concerned that the Company's internal operating standard pressure of 13 pounds per square inch gauge ("psig") for the Central District

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[49] The Central District is roughly a triangular area bounded by Everett, Wellesley/Newton, and Milton/Quincy. See 1987 Boston Gas Decision, 16 DOMSC at 254.

might constrain the Company's ability to use its full LNG vaporization capacity at Commercial Point.[50] Id., at 264. Therefore, the Siting Council ordered the Company to include in its next forecast filing:

> 7. a demonstration that, under assumed design day conditions, it has the ability to use: (1) all of its vaporizers simultaneously and at full capacity at its Commercial Point LNG facility, (2) all of its vaporizers simultaneously and at full capacity at its Lynn LNG facility, (3) all of its vaporizers simultaneously and at full capacity at its Salem LNG facility, and (4) all of its SNG and propane-air production capacity simultaneously and at full capacity at its Everett propane plant. Id., at 264, 271.

In response to Order Seven, the Company provided detailed and comprehensive network analyses of the performance of each of the facilities referenced in the Order under assumed design day conditions (Exhs. BGC-50, p. 3, BGC-51, BGC-52, BGC-53, BGC-54; Tr. 4, pp. 41-49).[51] The Company noted that these studies do not reflect how the Company would in fact typically operate on a design day (Exh. BGC-50, p. 7). However, these analyses demonstrate that, under assumed design day conditions, Boston Gas has the ability to use each of the facilities referenced in the second, third, and fourth parts of the Order at full capacity. Accordingly, the Siting Council finds that the Company has complied with the second, third, and fourth parts of Order Seven.

With respect to the first part of Order Seven which pertains to vaporization at Commercial Point in the Central District, the Company assumed in its network analysis an operating pressure of approximately 19 psig (Exh. BGC-51). This pressure is above the internal operating standard of 13 to

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[50] In this proceeding, the Company indicated that the internal operating pressure standard for the Central District is 13 to 15 psig (Exh. BGC-50, p. 8).

[51] The Company stated that a network analysis is a computerized simulation of the hydraulic performance of the Company's distribution system (Exh. BGC-50, p. 3).

15 psig set by the Company for the Central District (Exh. BGC-50, p. 8). While the Siting Council acknowledges that the purpose of the network analysis was to show operating capability rather than to demonstrate what normally would be done by the Company under design conditions, the Siting Council remains convinced that the ability to operate facilities at full capacity during design day conditions is vital as protection against supply contingencies which may occur during design conditions. Consequently, the Siting Council reviews the Company's arguments with respect to the MAOP of the Central District.

The Company argued that under the applicable Department of Transportation ("DOT") Regulations, the MAOP of the Central District is 22 psig (Exhs. BGC-50, pp. 9-10, HO-RR-12; Boston Gas Brief, pp. 25-26). The Company also argued that 22 psig is the "maximum safe pressure" for the Central District (Tr. 4, pp. 66, 86; Boston Gas Brief, p. 26). In support of this position, the Company referenced 49 CFR 192.619 and 49 CFR 192.621 (Exhs. BGC-50, p. 9, HO-RR-12).[52] The Company stated that, in pertinent part, 49 CFR 192.619 provides that steel or plastic pipelines may not be operated above the lowest of certain pressures including "the highest actual operating pressure to which the segment was subjected during the 5 years preceding July 1, 1970," and, the "pressure determined by the operator to be the maximum safe pressure" (_id._). The Company stated that the highest actual operating pressure experienced in the Central District during the timeframe identified by the DOT regulations was 22 psig (_id._, p. 10). In addition, the Company stated that under 49 CFR 192.621, cast iron pipes can be operated at a pressure of 25 psig (_id._, p. 9). Finally, the

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[52] The Company indicated that the distribution system in the Central District is a combination of steel, plastic, and cast iron pipes (Exh. BGC-50, p. 9). As a result, the Company maintains that both 49 CFR 192.619, which pertains to steel or plactic pipes, and 49 CFR 192.621, which pertains to cast iron pipes, apply to the Central District (_id._).

Company stated that it is revising its internal standards to eliminate confusion between these standards and MAOP (id.).

While the Company maintains that, pursuant to the DOT regulations, the MAOP of the Central District is 22 psig, the Company stated that the normal pressure it operates the Central District at is between 13 to 15 psig (Exh. BGC-50, p. 8). The Company also stated that this is an internal standard, and that operation of the distribution system at pressures above this standard requires the notification and approval of the senior management of the Company (id., pp. 8-9; Tr. 4, pp. 62-69). Further, the Company stated that when presented with a request to operate a distribution system above an internal standard, senior management may request that alternatives to operating above the internal standard, such as system reinforcements, be reviewed (Tr. 4, p. 63).

Boston Gas stated that typically it is necessary to operate the Central District distribution system above the internal standard once or twice during the winter, and more frequently if there is an extended cold spell (id., p. 68). The Company also stated that it would be necessary to operate the distribution system above the standard to meet anticipated load at 73 DD, the Company's design day standard (id., pp. 68-69). In addition, the Company stated that typically, it is the Central District that has an operating constraint (id., pp. 65-66). The Company stated that most of the other districts can operate "right up to MAOP" (id., p. 66).

The Siting Council notes that the DOT regulations may in fact be interpreted to mean that the MAOP of the Central District is 22 psig. The Siting Council also notes that any confusion as to the pressure at which the Company can operate in the Central District may amount to no more than an issue of semantics. However, based on the record in this proceeding, it clear to the Siting Council that operating contraints exist on the Company's Central District which prevent the Company from operating its distribution system in this District "right up to MAOP." In this proceeding, the Company has not specified these operating constraints, nor has it presented evidence

264-266. Therefore, the Siting Council ordered Boston Gas to develop and include a uniform design day planning standard for use in sendout forecasting, supply planning, and distribution system planning in its next forecast filing. Id., at 266, 271. The Siting Council also ordered the Company to include in its next forecast filing a long-term plan for reinforcing and redesigning its entire distribution system appropriate to a level of reliability equivalent to that amount assumed in the supply plan. Id., at 268, 271.

In response to these Orders, the Company asserted that based on the results of a network analysis of the distribution system's ability to meet anticipated 73 DD load for the 1987-88 heating season, its distribution system is capable of meeting the demands of a 73 DD design day (Exh. BGC-50, pp. 5; Boston Gas Brief, pp. 34-35). In addition, the Company presented a network analysis of the final year of the forecast, the 1992-93 split-year (Exh. BGC-50, p. 5). For that year, the Company stated that theoretical reinforcements would be required to meet anticipated 73 DD load (id., pp. 5-6; Exh. HO-SP-45). The Company indicated that some of these theoretical reinforcements would have to be made in the Mystic Valley/Lynn District, North Shore District, West District, and the South District (Exhs. HO-SP-45, HO-RR-11).[53] The Company stated that it has already made some of these reinforcements (Exh. HO-RR-11; Tr. 4, pp. 22, 35-39)

In addition, the Company stated that as part of its annual distribution planning process, it analyzes the performance of its distribution system and identifies reinforcements that are necessary to meet anticipated system loads (Exh. BGC-50, p. 6). As a result of this process, the Company identified and planned to install the following

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[53] The West District is roughly a triangular area bounded by Groton, Weston, and Burlington, while the South District includes the towns of Braintree, Weymouth, Hingham, Hull, Cohasset, Abington, Rockland, and Whitman. See: 1987 Boston Gas Decision, 16 DOMSC at 254, n. 5.

reinforcements prior to the 1988/89 winter: (1) approximately 650 feet of 8-inch gas main in Elliot Street, Beverly; (2) approximately 1,000 feet of 4-inch gas main along Chestnut Street, Lynnfield; (3) approximately 2,800 feet of 12-inch gas main along Summer Street, Hingham; and (4) approximately 7,640 feet of 12-inch gas main in Hingham (id.).[54]

In its responses to Orders Eight and Nine, the Company has demonstrated that it is implementing a plan to reinforce and redesign its distribution system in order to meet anticipated system loads and anticipated 73 DD load. Accordingly, the Siting Council finds that the Company has complied with Orders Eight and Nine of the 1987 Boston Gas Decision. However, the Siting Council notes that the Company has not planned or recently installed any reinforcements in the Central District. The Company has acknowledged that it has operating constraints in the Central District, and that it typically has to operate its distribution system in the Central District at pressures above the normal operating pressure standard of 13 to 15 psig during cold periods in the winter. Thus, the Siting Council ORDERS the Company to include in its next forecast filing: (1) 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 (2) if reinforcements are planned, to provide an itemized list of such reinforcements and an explanation of their expected impact on such operating constraints.

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[54] The Siting Council approved the petition of the Company to construct the 12-inch gas main of approximately 7,640 feet in Hingham in Boston Gas Company, 17 DOMSC 155 (1988). However, construction of that line could not commence at the time of that decision because the Company had not received an approval of a forecast and supply that included this facility.

c. Conclusions

In this proceeding, the Company has addressed many of the concerns raised by the Siting Council in the 1987 Boston Gas Decision, and has demonstrated that in most portions of its distribution system it can reliably distribute supplies under loads anticipated at 73 DD, the Company's design day standard. However, in this proceeding, the Siting Council has found that the Company has not made that demonstration for the Central District. While the Siting Council recognizes that operating pressures up to 19 psig may not be necessary at Commercial Point since the Company does not plan on using all its vaporization units at that LNG facility to meet anticipated design day requirements,[55] the Company has failed to address adequately the operating pressure requirements associated with meeting design day sendout in the Central District under base case or supply contingency scenarios.

Accordingly, for the purposes of this review, the Siting Council makes no finding as to whether the Company has established that its distribution is adequate to meet its forecasted requirements under design conditions throughout the forecast period. While the Siting Council acknowledges that significant improvements in the area of distribution planning have been made by the Company, the Siting Council also notes that this is the second consecutive case in which the Company has failed to adequately address the concerns of the Siting Council with respect to the operating pressure in the Central District. The Siting Council expects the Company to address these concerns in response to the orders in this Section. Further, the Siting Council places the Company on notice that it is of central importance that the Company respond adequately to the Siting Council's concerns on this issue.

55/ As previously indicated, the Company maintains one vaporization unit at Commercial Point as standby capacity. See Section III.D.2, above.

5. Conclusions on the Adequacy of the Supply Plan

The Siting Council has found that the Company has established: (1) that its normal year and design year base case supply plans are adequate to meet the Company's forecasted firm sendout requirements and storage refill requirements throughout the forecast period; (2) that Boston Gas has an action plan which would allow it to meet the resource deficiency during the 1990-91 design year in the event of a one-year delay in the PennEast CDS project and, therefore, has adequate resources to meet forecasted firm sendout requirements in the event that such a contingency occurs.

The Siting Council also has found that Boston Gas has established that its base case supply plan is adequate to meet forecasted firm design day sendout requirments for all years of the forecast period. In addition, the Siting Council has found that the Company's design day base case supply plan is adequate to meet forecasted firm sendout requirements in the event of a one-year delay in the PennEast CDS project.

Further, the Siting Council has found that the Company has complied with Orders Two, Three, Four, Five, Six, Eight, and Nine. The Siting Council also has found that the Company has complied with second, third, and fourth parts of Order Seven. However, the Siting Council has found that the Company has failed to comply with the first part of Order Seven. In addition, the Siting Council also has found that the Company has established that it has an adequate supply plan to meet its firm sendout requirements in the event of a cold-snap during the second year of the forecast period. Further, for the reasons set forth in Section III.E.4, above, the Siting Council has made no finding as to whether the Company has established that its distribution system is adequate to meet forecasted requirements under design conditions throughout the forecast period .

Accordingly, the Siting Council finds that, on balance, Boston Gas has established that it has adequate resources to meet its firm sendout requirement throughout the forecast period.

F. 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. 1989 Bay State Decision, EFSC 88-13, p. 80; 1989 Fitchburg Decision, EFSC 86-11(A), pp. 52, 55; 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; See: 1989 MECo Decision, 18 DOMSC at 337. 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. 1989 Bay State Decision, EFSC 88-13, p. 80; 1989 Fitchburg Decision, EFSC 86-11(A), p. 52; 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 two new long-term pipeline supply projects in its base case supply plan, NOREX and the PennEast CDS projects (see Section III.D.1, above). In addition, the Company has signed long-term gas supply agreements with ANE and Esso and associated precedent agreements for firm transportation with Iroquois, Tennessee, Algonquin and TCLP (Exhs. HO-SP-64, HO-SP-65). While Boston Gas chose not to include the ANE and Esso volumes in its base case supply plan, citing the remaining regulatory hurdles and consequent potential for delay in the delivery of these supplies (Tr. 6, p. 74), the Siting Council noted above that there is evidence in the record indicating that these supplies are expected to become available as early as November 1991, a date well within the forecast period (see Section III.D.1, above). Finally, the Company has made cost-based decisions regarding a new contract for LNG supplies and related services and the implementation of C&LM programs in the forecast period (see Sections III.F.2.d and III.F.2.e, below).

The Siting Council reviewed Boston Gas' plans to obtain pipeline supplies from the NOREX and ANE projects[56] in its previous decision. 1987 Boston Gas Decision, 16 DOMSC at 249-252. In that decision, the Siting Council strongly criticized the Company for failing to provide the required cost study for the ANE project, stating that "without formal analysis and documentation of the costs and benefits of new supplies, the Siting Council's mandate to verify that supply planning decisions are optimal is violated, and further, the Company denies itself of an organized method of analyzing and re-affirming past [supply] decisions." Id., at 249. The Siting Council also criticized the cost study submitted by the Company for the NOREX project, stating that "it failed to consider several critical factors," including various fixed and variable costs of the presented options, the impact of the options on customer rates, sensitivity analyses of important assumptions, tradeoffs between cost and reliability, and how the Company determined its level of participation (MDQ and annual contract quantity ("ACQ")) in the project. Id., at 251. The Siting Council also determined in that decision that the NOREX cost study failed to "consider a reasonable range of practical supply alternatives" since the scope of alternatives examined in that analysis was

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[56] At the time of the 1987 Boston Gas Decision, Boston Gas' ANE volumes were part of a Tennessee pipeline expansion proposal (Exh. BGC-75, pp. 8-9). Subsequently, the transportation of these same supplies was switched to the proposed Iroquois pipeline for a portion of their U.S. transportation (id.). See Section III.D.1, above.

limited to the proposed project and one alternative course of action -- using more propane. Id., at 250. Consequently, the Siting Council found that Boston Gas failed to establish that the NOREX project and the ANE project represented least-cost additions to the Company's supply plan. Id., at 250-252.

The overall supply planning process the Company used in making its supply decisions and the impact of its decisions on the adequacy of the Company's supply plan have been reviewed in Sections III.C and III.E, above. Here, the Siting Council reviews the Company's actual application of its supply planning process in making decisions regarding the NOREX project, PennEast CDS project, ANE and Esso volumes, new DOMAC LNG contracts, and C&LM programs, in order to determine whether each of these supply options contributes to a least-cost supply plan.

a. NOREX Project

i. Application of the Supply Planning Process

The Company's witness, Mr. DiGiovanni, stated that Boston Gas had identified NOREX as a supply alternative after several years of negotiations with Tennessee to increase pipeline deliveries to the northern part of Boston Gas' distribution system (Exh. BGC-2, p. 6). Mr. DiGiovanni noted that NOREX replaced the service initially proposed by Tennessee in the AVL-III Project (id., p. 7). Mr. DiGiovanni further stated that Boston Gas has needed the NOREX volumes since 1983 or 1984 and has been actively pursuing these supplies since 1984 (Tr. 1, pp. 26-29).

In the instant proceeding, Boston Gas provided a new cost study for the NOREX project (Exh. BGC-48). The study analyzed the impact on customer's rates of the addition of NOREX to the Company's gas supply portfolio (Exh. BGC-21, p. 34).

The NOREX cost study employed a comparison of projected gas and non-gas costs over a 20-year period for two scenarios -- with and without NOREX -- and concluded that NOREX would result in a total net present value savings of $42.68 million to ratepayers (id., pp. 34-35, Exh. BGC-48).

The Company also conducted a study to determine the optimal MDQ of gas to obtain from the project (Exhs. BGC-2, p. 7; HO-SP-11, HO-SP-11A). Using available cost and demand data, Boston Gas evaluated MDQ levels in increments of 10 MMcf per day up to 40 MMcf per day and determined that a volume of 40 MMcf per day would be optimal (id.).

In addition, Boston Gas indicated that it considered several non-price criteria in its decisionmaking process for the NOREX volumes. Specifically, the criteria of timing, operational considerations, and environmental impacts were incorporated in its evaluation (Exh. HO-RR-5).

With regard to timing, the Company stated that NOREX is expected to be available earlier than any alternative pipeline projects because of the advanced status of the project in the regulatory review process (id.). Boston Gas further stated that it had a critical need for such supplies by the 1989-90 heating season in order to avoid the curtailment of new loads (Exh. BGC-2, p. 6). In fact, the project received FERC certification in May, 1989 and the Company stated that it anticipated receiving a portion of its NOREX supplies beginning in November, 1989 (Exhs. HO-RR-5, HO-SP-62).

With regard to operational considerations, the Company stated that NOREX would increase deliveries to the northern section of its distribution system, an important benefit for the Company because of pressure problems and expected load growth in that area (Exhs. BGC-2, p. 6; HO-RR-5A; Tr. 6, pp. 141-143). In addition, the Company noted that NOREX would not require an extensive amount of new construction and therefore likely would involve relatively minor environmental impacts and a "relatively narrow environmental review process" (Exhs. BGC-2, p. 6, HO-RR-5A).

Mr. DiGiovanni asserted that Boston Gas had considered all other viable supply alternatives to NOREX at the time it elected to participate in the project (Exh. BGC-2, p. 7). Mr. DiGiovanni stated that Algonquin, Boston Gas' other pipeline supplier, was not offering any new gas supplies at that time (id., pp. 7-8). Mr. DiGiovanni also stated that DOMAC had filed for bankruptcy and that no Algerian LNG volumes were being imported into DOMAC's Everett terminal at that time (id.). The Company further stated that it did not consider spot gas to be a viable substitute for long-term gas supplies, and that it rejected the option of increased reliance on propane due to cost and reliability factors (id., p. 8). As noted above, in our last decision, Boston Gas had provided the Siting Council with an analysis of propane as an alternative to NOREX. 1987 Boston Gas Decision, 16 DOMSC at 250, 251.

The Company also provided an analysis of the viability of C&LM as an alternative to NOREX (Exhs. BGC-48, BGC-49). On the basis of this analysis, the Company concluded that C&LM measures could cost no more than $34 per MMBtu on average to be cost-effective relative to NOREX (id., Exh. BGC-21, p. 36). The Company stated that it was unlikely that a significant conservation potential could be generated for that price, asserting that the cost of typical large C&LM programs is $65 to $75 per MMBtu or more (Exhs. BGC-21, p. 36, HO-SP-42). Thus, the Company concluded that C&LM would not be a cost-effective alternative to NOREX (id.).

ii. Analysis

The Company's NOREX cost study clearly demonstrates that, given the stated set of assumptions, the project would result in a net benefit to the Company's ratepayers over time. In addition, the Company presented evidence that it had analyzed a reasonable set of alternative MDQ's for NOREX and had used the results of that analysis to determine the optimal level of its participation in the project. As such, the Company has addressed two of the Siting Council's major criticisms set forth in our last decision regarding the NOREX cost study. The NOREX cost study submitted in the instant case provides significant evidence in support of a conclusion that NOREX contributes to a least-cost supply plan.

However, the Company failed to adequately address the

Siting Council's other criticisms of the earlier NOREX cost study. The Company did not perform a sensitivity analysis of the underlying assumptions of the new cost study. In addition, while the Company did attempt to broaden its analysis of possible practical alternatives by providing an assessment of the relative cost-effectiveness of NOREX and C&LM, its study lacked adequate documentation and generally was unclear. For example, the Company provided no clear explanation of how the $34 per MMBtu breakeven figure for C&LM was derived and provided no documention for its assertion regarding the average costs of C&LM.

Nonetheless, the Siting Council recognizes that the Company has made significant progress in its efforts to adopt least-cost supply planning in general and, in particular, to document that the NOREX project contributes to a least-cost supply plan.

Accordingly, the Siting Council finds that Boston Gas properly applied its supply planning process in reaching a decision on the NOREX volumes and that the addition of these volumes to their supply portfolio contributes to a least-cost supply plan.

b. PennEast CDS Project

i. Application of the Supply Planning Process

Mr. Luthern stated that Boston Gas identified the PennEast CDS project as a possible supply option in 1987 as the result of a process of negotiation and discussion with other gas utilities, pipeline companies, gas suppliers, and others (Exhs. BGC-75, pp. 9-10, HO-SP-39). The Company asserted that a need for new supplies to serve its traditional customer sectors, as well as new markets such as cogeneration, gas air conditioning, and electrical replacement load, also became apparent in 1987 (Exh. BGC-75, p. 9). The Company asserted that it focused its interest on the PennEast CDS project because it was one of the few Open Season projects which would directly serve the Company's service territory (Tr. 6, pp. 33-34).

Boston Gas submitted initial and revised cost studies for the PennEast CDS project which evaluated the impact of the project on: (1) the Company's gas costs; (2) revenues from adding new firm load; and (3) profit from off-peak sales to the cogeneration, power generation, and interruptible markets (Exhs. HO-SP-40, HO-SP-40A, HO-SP-40C - HO-SP-40E). From these studies the Company determined that the rate impact of the project would be negative in the short-run, but would gradually improve and become positive as new loads are added (id.). The Company's calculations indicate that, given its set of assumptions, its firm customers would benefit from a reduction in rates of $27.8 million on a net present value basis over the 27-year time period of the revised cost study (Exhs. HO-SP-40C, HO-SP-40E; Tr. 3, pp. 73-77).[57]

The Company stated that it considered three non-price criteria -- source of gas supply, environmental impacts, and operational considerations -- in addition to price in its evaluation of the PennEast CDS project (Exh. HO-RR-5). With regard to the gas supply source, the Company stated that under the PennEast CDS project it will be receiving existing domestic supplies which are available because of a decline in demand in other regions of the country (id.). Due to the source of supply, the Company stated that it had a high degree of confidence that the project would be completed (Tr. 6, pp. 79-80). With regard to environmental impacts, Boston Gas stated that the PennEast CDS volumes would be delivered by means of an expansion of existing pipeline networks, thereby minimizing the need for new construction (id.; Exh. HO-RR-5). Finally, in terms of operational impacts, the Company asserted that it would gain enhanced operational flexibility and strength from the PennEast CDS deliveries (Exh. BGC-75, p. 9; Tr. 6, p. 79).

57/ The final year of the cost study (2016) was selected by the Company because it was the twentieth year after the PennEast CDS supplies are projected to sell out in firm traditional markets (Exh. HO-SP-40C). The PennEast CDS precedent agreement provided by the Company does not specify a termination date (Exh. BGC-3).

ii. Analysis

The detailed cost studies of the PennEast CDS project performed by Boston Gas, together with the Company's discussion of the application of non-price criteria in its evaluation process, provided significant support for the Company's assertion that the PennEast CDS project would contribute to a least-cost supply plan. The Company's cost study established to our satisfaction that, given the Company's assumptions, the PennEast CDS project would result in lower rates over time for the Company's firm ratepayers than would be the case in the absence of the project. The Company's description of the non-price aspects of the project, while lacking in detail, demonstrated that the project was attractive in terms of its supply source, environmental impacts, and operational considerations.

However, the Siting Council notes that the analysis and supporting documentation presented by the Company are lacking in some important respects and generally are inferior to those presented by the Company for the NOREX volumes. Most significantly, the Company failed to compare the PennEast CDS volumes with a reasonable range of supply alternatives, a step which the Siting Council has found to be vital in making resource decisions. 1987 Boston Gas Decision, 16 DOMSC at 248-252; 1986 Gas Generic Order, 14 DOMSC at 100-102. While Boston Gas' revised PennEast CDS cost study indicates that the project would result in lower rates for the Company's customers, by failing to compare the PennEast CDS project to potential alternatives, the Company, in this record, has not established that the PennEast CDS option is the lowest cost option available to the Company and that its customers are receiving the maximum achievable cost savings.

In addition, the Siting Council notes that the time period selected by the Company for the PennEast CDS cost analysis is not appropriate. The time frame for the analysis should be based on the length of the gas supply and transportation agreements, or some other appropriate time frame, not an arbitrary length of time after the gas supplies are projected to sell out to firm customers.

Boston Gas also failed to present evidence regarding its choice of an MDQ of 29.2 MMcf per day as its level of participation in the project and to perform a sensitivity analysis of the important assumptions underlying its cost analysis.

Despite these problems with Boston Gas' analysis, the Siting Council recognizes that the Company has made progress in documenting its decisionmaking process and has presented reasonable evidence in support of its decision to participate in the PennEast CDS project. Accordingly, for the purposes of this review, the Siting Council finds that Boston Gas properly applied its supply planning process in reaching a decision on the PennEast CDS volumes and that the addition of these volumes to their supply portfolio contributes to a least-cost supply plan.

c. ANE and Esso Volumes

i. Exclusion from Base Case Supply Plan

Boston Gas indicated that it did not include the ANE and Esso volumes in its base case supply plan because of its concerns that the pipeline capacity to transport these volumes would not be in place until after the end of the forecast period (Exh. HO-SP-67; Tr. 6, pp. 72-74). See Section III.D.1, above. Elsewhere in the record, however, the Company in numerous instances indicated that it expected to begin to receive the ANE/Esso volumes by November 1991, the scheduled delivery date for these volumes and a date well within the forecast period (Exhs. HO-SP-13, HO-SP-51, HO-SP-64).

The Siting Council acknowledges the Company's concerns regarding the potential time delays associated with the delivery of the ANE and Esso volumes. However, the Company has an obligation to include in its base case supply plan any planned supply which can reasonably be anticipated to come on-line within the forecast period. When the planned supplies are scheduled to come on-line within the forecast period but significant uncertainties exist regarding the timing or viability of these supplies, the Siting Council will assess these uncertainties by means of a contingency analysis within the supply adequacy section of its decisions.

The Siting Council finds that there is sufficient evidence in the record to indicate that the ANE/Esso supplies are expected to become available to Boston Gas as early as November, 1991, a date well within the forecast period, and therefore that these supplies should have been included in the Company's base case supply plan. Accordingly, the Siting Council ORDERS Boston Gas in all future forecast filings 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.

The Siting Council notes that there clearly are cost implications associated with Boston Gas' decision to acquire the ANE and Esso supplies, including the potential costs to the Company and its ratepayers should the markets for these supplies fail to fully materialize as expected. Given these cost implications and the finding above that the Company should have included the ANE/Esso volumes in its base case supply plan, the Siting Council evaluates below whether Boston Gas has properly applied its supply planning process in reaching a decision on the ANE/Esso volumes, and whether these volumes contribute to a least-cost supply plan.

ii. Application of the Supply Planning Process

The Company's plans to transport two incremental gas supplies, the ANE and Esso volumes, via the Iroquois/Tennessee project emerged relatively late in the instant proceeding. These plans emerged as the result of changes in the Iroquois/Tennessee project as well as in two other pipeline proposals -- the ANE project and the Champlain project -- in which the Company had originally planned to participate (Exhs. BGC-75, p. 8, HO-SP-64). Mr. Luthern stated that Boston Gas' interest in obtaining additional volumes of Canadian gas led it to join five other gas utilities and Tennessee in early

1986 in an effort to expand shipments on the Tennessee system (Exh. BGC-75, p. 8). The Company stated that it preferred the Tennessee option for transporting its ANE volumes because the rate structure of the proposed Iroquois pipeline at that time was unfavorable for transporting gas into the Company's service territory (id., pp. 8-9). According to Mr. Luthern, in 1988, during the course of the Open Season settlement negotiations, the Iroquois and ANE projects were merged, and the Company's rate related concerns were resolved (id., p. 9).

Boston Gas indicated that it also had been a participant in the Champlain project since its beginnings in 1987 (id., p. 10). The Company stated that it viewed Champlain as having several attractive features, such as cost and the fact that the project would directly serve eastern Massachusetts (Exh. HO-RR-5A). However, as the result of the difficulties experienced by Champlain in late 1989, the Company terminated its precedent agreement with Champlain and switched the Esso volumes which it had planned to ship on Champlain to the Iroquois project (Exh. HO-SP-64). See Section III.D.1, above.

Mr. Luthern stated that the Company focused its interest on the ANE and Champlain projects, and later the Iroquois project, because they were among the few proposed projects which would directly serve the Company's service territory (Tr. 6, pp. 33-34). The Company asserted that a need for the new supplies that these projects would bring had become apparent only recently, at about the same time as the proposals for new pipeline capacity emerged (Exh. BGC-75, pp. 9-11).

Boston Gas submitted initial and updated cost studies for the ANE and Esso volumes which examined the net present value of the costs and benefits of the new supplies to the Company over time (Exhs. HO-SP-40B, HO-SP-40C, HO-SP-40F).[58] The same methodology employed for the PennEast CDS cost studies was also employed for the ANE/Esso cost studies (Exh. HO-SP-40C).

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[58] The Company's initial and revised cost studies were for the combined ANE and Esso volumes.

The studies indicate that the rate impact of the ANE/Esso volumes would be negative in the short-run, but would gradually improve and become positive as new loads are added (id.). The Company's calculations indicate that over the 33-year time period of the revised cost study,[59] its firm customers would benefit from a net reduction in rates of $30.3 million on a net present value basis (Exhs. HO-SP-40C, HO-SP-40E; Tr. 3, pp. 73-77).

The Company apparently also considered three non-price criteria -- diversity of gas supply, competitive advantage, and operational benefits -- in addition to price in its evaluation of the ANE/Esso supplies (Exhs. HO-RR-5A, HO-SP-38).

With regard to diversity of supply, the Company asserted that additional Canadian supplies would assist the Company in minimizing the risk of supply interruptions and that its future needs could not be met solely from available domestic supplies (id.). With regard to competitive advantage, the Company asserted that the addition of the Iroquois pipeline to serve Northeastern markets would increase the competition for Boston Gas' business among all pipelines to the Northeast (Exh. HO-SP-38). The Company did not elaborate on the operational benefits it expects to receive from the project.

The ANE and Esso volumes together total 52 MMcf per day, a sizeable increase (on the order of 14 percent) in the Company's firm pipeline commitments (Exhs. HO-SP-65, HO-SP-67). The Company indicated that a significant portion of these new volumes will be used to serve non-traditional markets such as cogeneration, electrical replacement load, and gas air conditioning (Exh. BGC-75, p. 11). The Company stated that it was confident that it could achieve a sufficient level of sales to these emerging markets to justify the costs associated with

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59/ The final year of the cost study (2024) was selected by the Company because it was the twentieth year after the Iroquois volumes are projected to sell out in firm traditional markets (Exh. HO-SP-40C).

these additional supply commitments (Tr. 2, p. 127).

Mr. Luthern addressed the Company's contingency plans should the new markets fail to materialize as expected (Exh. BGC-75, pp. 12-14). According to Mr. Luthern, under such circumstances the Company would consider several options, including: (1) increasing sales to large existing interruptible customers such as the Boston Edison Company; (2) developing new markets, including gas resale to other gas utilities in the U.S. or Canada; (3) exercising its full contractual rights under the gas sales and transportation agreements; (4) conversion of existing obligations for sales to transportation; and (5) restructuring of its existing gas supply portfolio as contracts terminate or come up for renewal (id., Tr. 6, pp. 143-145).

iii. Analysis

The Siting Council finds that the analysis and supporting documentation provided by Boston Gas in support of its assertion that the ANE and Esso volumes would contribute to a least-cost supply plan are lacking in several respects.

First, the Company's updated cost study indicated that, given the Company's assumptions, the ANE/Esso volumes would result in lower rates over time for the Company's firm ratepayers than would be the case in the absence of the project. However, this cost study was based on assumptions that appear to be inconsistent in some respects with other information in the record: (1) the cost study indicates a startup date for the ANE/Esso volumes of 1991/92, whereas these volumes are not included at all in the Company's supply plan which runs through 1992/93 (Exhs. HO-SP-40F, HO-SP-67); and (2) the sendout forecast used in the cost study is different from the sendout forecast provided by the Company in this proceeding (id.). These inconsistencies raise doubts regarding the ultimate results of the Company's cost analysis.

Second, as with the Company's PennEast CDS cost analysis (see Section III.F.2.b.ii, above), the time period selected by the Company for the ANE/Esso cost analysis is not appropriate. The time frame for the analysis should be based on the length of the gas supply and gas transportation agreements, or some other appropriate time frame, not an arbitrary length of time after the gas supplies are projected to sell out to firm customers. The transportation agreement between Boston Gas and Iroquois for the ANE and Esso volumes includes a provision which allows either party to terminate the agreement at the end of 20 years (Exhs. HO-SP-13B, p. 6, HO-SP-65B). By employing a 20 year rather than a 33 year cost horizon, Boston Gas' cost analysis indicates that the net present value of its participation in Iroquois would be a benefit of $9.8 million, considerably less than the Company's assertion of a $30.3 million benefit (Exh. HO-SP-40F).

Third, the Company failed to compare the ANE/Esso volumes with a reasonable range of supply alternatives, a step which the Siting Council has found in the past to be vital in making resource decisions. 1987 Boston Gas Decision, 16 DOMSC at 248-252; 1986 Gas Generic Order, 14 DOMSC at 100-102.

Consequently, Boston Gas, in this record, has not established that the ANE/Esso volumes are the lowest cost option available to the Company and that Boston Gas' ratepayers are receiving the maximum achievable cost savings.

In addition, Boston Gas failed to present evidence regarding its choice of an MDQ of 52 MMcf per day as its level of participation in the project or to perform a sensitivity analysis of the important assumptions underlying its cost analysis.

The Siting Council also notes that the Company's explanation of the role of non-price criteria in its evaluation of the ANE and Esso volumes is less detailed and less informative than similar explanations for its other planned pipeline supplies. This lack of documentation raises questions about the consistency of the Company's application of its resource evaluation process. In the future, the Company will be required to provide a clear description of its selected non-price criteria and demonstrate the consistent application of these criteria in its resource evaluation process.

The Siting Council also recognizes that the Company is taking some risks in procuring new pipeline supplies designed, in large part, to serve non-traditional markets such as cogeneration projects. In light of the Commonwealth's strong support for cost-effective cogeneration, the relative environmental attractiveness of natural gas as a fuel for such plants, and the recent difficulties encountered by cogeneration developers in independently obtaining long-term supplies of natural gas, Boston Gas' actions, if they could be shown to be compatible with a least-cost supply plan, would be commendable.

At the same time, however, the Siting Council notes that the potential volumes associated with these emerging markets are sizeable relative to the Company's existing sales and that significant uncertainties exist with regard to the ultimate size and rate at which these markets may develop (see Section II.D.3, above). In light of these uncertainties, it is appropriate for gas companies to prepare responsible and comprehensive contingency plans in order to respond to the possibility that such new markets may fail to fully materialize as expected.

Boston Gas addressed this issue briefly in its testimony and enumerated several possible options that it could undertake in such circumstances (Exh. BGC-75, pp. 12-14; Tr. 6, pp. 143-145). These options appear to be reasonable. However, while we encourage gas companies to continue to take steps to serve these important new markets, in the future the Siting Council will require gas companies that actively are pursuing emerging markets to provide more detailed and comprehensive contingency plans and to establish that they have appropriately balanced the potential risks and benefits of adding new supplies to serve emerging non-traditional markets.

The Siting Council acknowledges that the changing circumstances and uncertainties associated with the Company's participation in various Open Season pipeline projects to transport the ANE and Esso volumes have made it difficult for the Company to present consistent and coherent documentation in support of its contention that these volumes represent least-cost additions to its supply portfolio. Nevertheless, the Siting Council requires such documentation in order to make a finding that such new supplies constitute a least-cost addition. Such documentation is particularly important where the planned new supplies are substantial in size and in large part involve sales to emerging markets. The evidence presented by the Company in the record of the instant proceeding is inadequate for the Siting Council to make such a determination.

Accordingly, the Siting Council finds that Boston Gas has failed to establish that it properly applied its supply planning process in reaching a decision on the ANE/Esso volumes. The Siting Council therefore finds that the Company failed to establish that the addition of these volumes to its supply portfolio contributes to a least-cost supply plan.

In its next filing, Boston Gas is ORDERED to provide the following documentation and analyses for the ANE/Esso volumes: (1) complete documention 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; (2) full documentation of the role of non-price criteria in the application of its supply planning process to these volumes; (3) an updated cost study based on: (a) assumptions which are fully consistent with those contained in the remainder of the filing, particularly the projected resources and requirements tables; and (b) a time frame based on the length of the gas supply and transportation agreements or some other appropriate time frame; (4) a study of the sensitivity of the results of the updated cost analysis to changes in the major assumptions underlying the analysis; (5) a description and analysis showing how the Company determined its level of participation (MDQ and ACQ) in the planned supply project; (6) a more detailed discussion of the Company's contingency plans should the markets for these volumes fail to materialize as expected; and (7) a detailed discussion of how the Company has balanced the potential risks and benefits of serving the targeted markets for these volumes.

d. DOMAC Contracts

i. Application of the Supply Planning Process

In June 1988, Boston Gas entered into a settlement agreement with DOMAC wherein the parties resolved certain disputes and agreed to enter into contracts for new LNG sales, storage, and transportation services (see Section III.D.2.a, above) (Exh. BGC-2, p. 10). Mr. Luthern, stated that the Company views the new arrangement as having significant economic and operational benefits (Exh. BGC-75, p. 16). The restructured contracts include the following cost-related elements:

- Boston Gas will increase its storage entitlements at the Everett facility to 1,000 MMcf, up from 643 MMcf, while maintaining current storage charges (Exh. BGC-2, pp. 11-12, Tr. 1, pp. 58-59).
- Boston Gas will be able to purchase all of the LNG boiloff from DOMAC's Everett terminal (up to 3,300 MMBtu per day) at the Company's avoided cost of pipeline gas (id.).
- Boston Gas, at its sole option, will be able to purchase 2,000 MMcf of LNG at a price 10 cents per MMBtu less than the Company's avoided cost of liquefaction at its Commercial Point facility (id.).
- Under a backup gas purchase contract, at DOMAC's request Boston Gas will purchase specified quantitiies of LNG at a rate of one cent per MMBtu less than the Company's avoided pipeline commodity cost (id.).
- Boston Gas will provide firm transportation for vaporized LNG for DOMAC, although Boston Gas' own needs will take precedence. According to Mr. Luthern, this transportation service will provide the Company's firm customers with a substantial flowback of revenues with no operating risks (id., BGC-75, p. 16).

Mr. DiGiovanni and Mr. Luthern both indicated that the Company considered operational and reliability issues as well as cost in its evaluation of the restructured agreement (Exh. BGC-75, p. 16; Tr. 1, pp. 38-40, 54-59). Mr. DiGiovanni stated that one of Boston Gas' top priorities was to obtain a large, secure gas storage volume within its service territory (Tr. 1, pp. 38-40, 55). Mr. DiGiovannni also stated that other key issues for the Company included the ability to secure increased vaporization capabilities to serve design day needs and obtaining backup for the Company's own liquefaction capabilities (id., pp. 39, 56). In addition, the Company cited the importance of the DOMAC facilities being connected directly to several of the Company's major distribution lines (id.). Mr. Luthern indicated, however, that Boston Gas would continue to avoid depending on DOMAC shipments in the heating season to meet the needs of the Company's firm customers because of its concerns regarding the reliability of imported LNG (Tr. 6, pp. 86-91).

ii. Analysis

The Siting Council notes that Boston Gas failed to conduct a cost study comparing the DOMAC volumes to other supply options, including C&LM, a step which we have found to be vital in making resource decisions.[60] However, the Siting Council also recognizes that the new agreements with DOMAC maintain current prices or include a built-in discount to the Company's avoided pipeline

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[60] The 1986 Gas Generic Order requires gas companies to submit a cost study comparing a reasonable range of supply alternatives when considering "major new supply options." 1986 Gas Generic Order, 14 DOMSC at 101, 102. While the new contracts between Boston Gas and DOMAC involve the restructuring of a former agreement rather than a totally new supply, they include provisions for increased storage entitlements and purchases. Consequently, the Siting Council finds that restructuring of the DOMAC contracts constitutes a "major new supply option," thereby triggering the need for a cost study.

or LNG liquefaction costs, thereby essentially guaranteeing that the contracts will benefit the Company's firm ratepayers. As such, the agreements clearly contribute to a least-cost supply plan. Nonetheless, the submission of a cost study, which at a minimum compares the DOMAC volumes with C&LM, would have been appropriate in this case in order to assure that ratepayers receive the lowest cost supply, as opposed to merely a lower cost supply.

In addition, the Company's discussion of the non-price attributes of the new DOMAC agreements showed that the Company adhered to its planning criteria in its analysis of the agreements and that the DOMAC supplies have certain unique reliability and operational benefits for Boston Gas' distribution system.

Accordingly, for the purposes of this review, the Siting Council finds that Boston Gas properly applied its supply planning process in reaching a decision on the new DOMAC contracts, and that the addition of these volumes to the Company's supply portfolio contributes to a least-cost supply plan.

e. Conservation and Load Management

i. Application of the Supply Planning Process

As discussed in detail in Section III.C.2.c, above, the Company is presently in the early stages of identifying and evaluating C&LM programs. Mr. Tomlinson stated that while Boston Gas is moving forward in its efforts to identify cost-effective C&LM programs of various types, its primary focus at present is implemention of a new conservation program for public housing authorities in its service territory, the PHA program (Tr. 3, pp. 40-41). Under the PHA program, Boston Gas will finance, with a zero interest loan, all cost-effective conservation investments identified in technical energy audits of public housing authorities conducted by qualified energy engineering firms (Exh. HO-SP-66A, p. 6). Mr. Tomlinson noted that public housing authorities are somewhat unique in that they may be unable to make C&LM

investments that are clearly cost-effective due to a lack of capital (Tr. 3, p. 41).

The Company indicated that it initially identified the PHA program as the result of documentation provided by the Boston Housing Authority ("BHA") during the course of the Company's most recent rate case before the MDPU (id., p. 49). Boston Gas indicated that it employed a single evaluation criterion -- cost-effectiveness -- to determine which individual C&LM measures to implement under the PHA program (Exh. HO-SP-66A, p. 6). The Company stated that it evaluated the cost-effectiveness of such measures using the avoided cost test, as required by the MDPU, and that it will implement identified C&LM measures which it determines would be less expensive than its MDPU-approved avoided costs (id., pp. 6-7).

The Company stated that it has conducted audits of all of the BHA properties and has identified approximately $605,000 of cost-effective conservation investments to date (id., p. 8). Boston Gas stated that it is coordinating its BHA program activities with a group consisting of representatives from the BHA, Central Maintenance and Management, and Mass-Save, Inc. (id., p. 9). The function of this group is to review final audit analyses and recommendations, to identify the need for any further engineering studies, and to coordinate implementation plans (id.). The Company stated that it has also held discussions with representatives of the Somerville Housing Authority and that it plans to expand the PHA program in the fall of 1989 (id., p. 7).

The Company did not offer an analysis of the non-price attributes of the PHA program.[61]

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[61] The Siting Council previously criticized Boston Gas for its failure to include an assessment of non-price criteria in its supply planning process for C&LM programs (see Section III.C.2.c, above).

decision on the PHA program and that the addition of these supplies contributes to a least-cost supply plan.

In recent decisions regarding gas companies supply plans, the Siting Council has stated that there is no apparent reason for gas companies to exclude C&LM from their base case resource plans, noting that conservation measures are fully capable of providing gas companies with cost-effective, reliable resources (see 1989 Bay State Decision, EFSC 88-13, p. 89; 1989 Fitchburg Decision, EFSC 86-11(A), p. 42). Similarly, we find here that Boston Gas should include cost-effective C&LM programs in its base case supply plan in the future.

Therefore, the Siting Council ORDERS Boston Gas in its next filing to: (1) quantify the savings of its existing and planned C&LM programs over the forecast period; and (2) fully incorporate these estimates into its base case resource plan and its analyses of adequacy for normal and design conditions.

3. Conclusions on Least-Cost Supply

The Siting Council has found that Boston Gas properly applied its supply planning process in reaching decisions regarding the NOREX, PennEast, and Distrigas/DOMAC volumes as well as its conservation program for Public Housing Authorities. The Siting Council also has found that each of these supply decisions contributes to a least-cost supply mix. The Siting Council also has found that Boston Gas has failed to establish that it properly applied its supply planning process in reaching a decision on the ANE/Esso volumes and has consequently failed to establish that the addition of these volumes would contribute to a least-cost supply plan.

Boston Gas has addressed some of the criticisms contained in the previous decision regarding the Company's application of its supply planning process. For example, the Company submitted detailed cost studies for the NOREX, PennEast CDS and ANE/Esso volumes and indicated that it would use the avoided cost test to determine which C&LM measures to implement under the PHA program. With the exception of the PHA program, the Company provided at least some discussion of the non-price attributes of each of its planned supply additions.

However, the Company failed to address other criticisms from the previous decision regarding the documentation of the Company's application of its supply planning process. For example, with the exception of the NOREX cost study, the Company failed to compare its planned supplies to a range of practical alternatives, a vital step in establishing that the each of the planned supplies is the least-cost option. Again, with the exception of its NOREX cost analysis, the Company failed to explain how it determined the optimal MDQ for the planned supply. The Company also consistently failed to provide sensitivity analyses for the major assumptions contained in its cost analyses. In certain cases, the assumptions contained in these analyses were not appropriate or were inconsistent with other information in the record. The Company also failed to provide a discussion of non-price criteria for the PHA program. This lack of adequate documentation made it more difficult for the Siting Council staff to determine whether each of the various planned supplies constituted a least-cost supply addition and led to the Siting Council's inability to make a positive finding regarding the ANE/Esso volumes.

Accordingly, 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 supply plan minimizes cost.

In Section III.F.2.b.ii, above, the Siting Council specifically ordered Boston Gas to provide more documentation and analysis in support of its assertion that the ANE/Esso volumes contribute to a least-cost supply plan in its next filing. The Siting Council concludes that it also is appropriate for Boston Gas to provide such information for other planned supply resources in the future. Accordingly, in the future, when large increments of new supplies are added to the Company's supply plan, Boston Gas is ORDERED to: (1) 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, in applying its supply planning process, as required by the <u>1986 Gas Generic Order</u>, 14 DOMSC at 100-102; (2) fully document the role of non-price criteria in the application of its supply planning process; (3) utilize assumptions in its cost study which are: (a) fully consistent with those contained in the applicable sendout forecast and supply plan, particularly the projected resources and requirements tables; and (b) include a time frame for the cost study based on the length of the gas supply and transportation agreements or some other appropriate time frame; (4) provide a study of the sensitivity of the results of the cost analysis to changes in the major assumptions underlying the analysis; (5) 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) provide a detailed discussion of the Company's contingency plans should the markets for the planned volumes fail to materialize as expected; and (7) provide a detailed discussion of how the Company has balanced the potential risks and benefits of serving the targeted markets for these volumes.

G. <u>Conclusions on the Supply Plan</u>

In previous sections of this decision, the Siting Council has found that Boston Gas has established that: (1) its supply planning process is minimally sufficient to enable it to make least-cost supply decisions; (2) it has adequate resources to meet its firm sendout requirements throughout the forecast period; 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 1988 supply plan of Boston Gas Company.

In approving the Company's supply plan, the Siting Council notes the important strides made by the Company since our last decision. In this proceeding, the Company has demonstrated that it has made significant progress in developing and documenting an appropriate supply planning process. The Company submitted detailed cost studies for the NOREX and PennEast CDS projects, and indicated that it would use the avoided cost test to determine which C&LM measures to implement under the PHA program. In addition, Boston Gas appears to have improved its criteria for judging resources. The additional amounts of pipeline gas the Company has contracted should reduce the Company's reliance on more expensive and less reliable supplemental supply sources, and allow the Company to more fully pursue the non-traditional cogeneration markets.

Nonetheless, the Company's supply plan contains certain marked infirmities. First, the Company has not demonstrated that it can operate above normal operating pressure of 13 to 15 psig in its Central District under design conditions. As indicated previously, it of critical importance that the Company make this demonstration in its next filing.

Secondly, the Company's supply planning process currently does not consider non-price criteria in its evaluation of C&LM options. Because of this deficiency, Boston Gas cannot adequately compare a particular C&LM resource with other C&LM resources, nor can it adequately compare C&LM resources with traditional supply resources. In addition, the Company does not include planned savings from conservation programs in its base case supply plan, such as energy savings from its PHA program. As a result, the Company's process continues to demonstrate some bias against non-traditional supply resources,

Throughout this decision, the Siting Council has recognized the limited experience which gas companies have acquired thus far with C&LM programs and has accepted that the initial efforts to consider these programs may be less than comprehensive. However, at the same time that we commend Boston Gas for taking a leadership role in the development of C&LM programs, we must also emphasize that the time for initial efforts now has passed, and the Company, in its next forecast and supply plan filing, must demonstrate it has fully integrated C&LM into the its supply planning process and decisions.

IV. DECISION AND ORDER

The Siting Council hereby APPROVES the sendout forecast and supply plan of Boston Gas Company as presented in its First Supplement to its Third Long-Range Forecast.

The Siting Council ORDERS Boston Gas in its next forecast filing:

1. to 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 Airport 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;

2. 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;

3. 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;

4. to include territory specific studies designed to develop a reliable database of building types, energy use, and market potential for traditional cogeneration development;

5. 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;

6. (a) to develop an appropriate set of non-price criteria for C&LM as well as for traditional supply options (see Section III.C.2.c.ii.n.32, above); (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;

7. to submit an updated cold snap analysis;

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 reasonble 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;

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.

10. (a) to provide complete documention 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;

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.

The Siting Council ORDERS Boston Gas in all future forecast filings 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.

The Siting Council further ORDERS the Company, in the future 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, in applying its supply planning process, as required by the 1986 Gas Generic Order, 14 DOMSC at 100-102; (2) to fully document the role of non-price criteria in the application of its supply planning process; (3) to utilize assumptions in its cost study which are (a) fully consistent with those contained in the applicable sendout forecast and supply plan, particularly the projected resources and requirements tables, and (b) include a time frame for the cost study 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.

The Siting Council further ORDERS Boston Gas to file its next forecast on April 1, 1991.

Frank P. Pozniak
Hearing Officer

Dated this 9th day of February, 1990.

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of February 9, 1990 by the members and designees present and voting. Voting for approval of the Tentative Decision as amended: Paul W. Gromer (Commissioner of Energy Resources); Barbara Kates-Garnick (for Mary Ann Walsh, Secretary of Consumer Affairs and Business Regulation); Joellen D'Esti (for Alden S. Raine, Secretary of Economic Affairs); Joseph Freeman (for John P. DeVillars, Secretary of Environmental Affairs); Joseph Joyce (Public Labor Member); Sarah Wald (Public Environmental Member); and Kenneth Astill (Public Engineering Member).

Paul W. Gromer
Chairperson

Dated this 9th day of February, 1990

TABLE 1

Boston Gas Company
Forecast of Firm Sendout by Customer Class

Normal Year
(MMcf)[1]

Customer Class	1989-90 Heating Season	1989-90 Non-heating Season	1992-93 Heating Season	1992-93 Non-heating Season
Residential Heating	24,396	10,622	24,455	10,540
Residential Non-heating	1,775	1,884	1,675	1,757
Commercial	14,892	8,391	16,302	9,334
Industrial	3,204	1,787	3,258	1,765
Total Sendout[2]	48,385	22,412	50,000	22,932

Design Year
(MMcf)[1]

Customer Class	1989-90 Heating Season	1989-90 Non-heating Season	1992-93 Heating Season	1992-93 Non-heating Season
Residential Heating	27,054	11,370	27,033	11,263
Residential Non-heating	1,904	2,001	1,785	1,848
Commercial	16,528	8,728	18,033	9,695
Industrial	3,367	2,123	3,412	2,091
Total Sendout[2]	53,455	23,610	55,056	24,087

Notes:

1. One BBtu is assumed to equal one MMcf.

2. Includes Wakefield sales, company-use, and unaccounted for gas.

Source: Exh. HO-RR-17, Tables G-1 through G-5

TABLE 2

Boston Gas Company
Base Case Design Year Supply Plan
Heating Season
(MMcf)[1]

Firm <u>Requirements</u>:	<u>1989-90</u>	<u>1990-91</u>	<u>1991-92</u>	<u>1992-93</u>
Firm Sendout	53,768	55,030	55,560	56,271
Storage Refill:				
LNG Liquefaction	299	414	435	399
Fuel Reimbursement	120	85	88	90
TOTAL	54,187	55,529	56,083	56,760

Firm <u>Resources</u>:	1989-90	1990-91	1991-92	1992-93
TGP CD-6	13,133	13,063	13,109	13,176
TGP NOREX	3,017	5,822	5,829	5,838
TGP Storage Return	1,521	1,263	1,301	1,335
Boundary	1,545	1,545	1,545	1,545
Iroquois/ANE	0	0	0	0
AGT F-1	19,072	19,135	19,137	19,140
AGT F-2	2,514	1,988	2,035	2,106
AGT F-3	944	944	944	944
AGT WS-1	2,644	2,644	2,644	2,644
AGT STB	2,935	2,108	2,162	2,227
AGT SS-III	812	562	591	595
PennEast CDS	0	3,271	3,329	3,388
LNG from Storage	3,505	2,358	2,556	2,829
DOMAC LNG	1,498	1,493	1,493	1,493
Firm Propane Purchases	1,182	0	0	0
TOTAL	54,322	56,196	56,675	57,260
<u>Interruptible Sales</u>[2]:	135	667	592	500

<u>Notes</u>:

1. One BBtu is assumed to equal one MMcf.

2. These sales reflect the Company's present supply plans. The Siting Council recognizes that actual interruptible sales will vary as available supplies vary.

<u>Source</u>: Exhs. HO-SP-67, Table G-22D, page 1

TABLE 3

Boston Gas Company
Base Case Design Year Supply Plan
Non-Heating Season
(MMcf)[1]

Firm Requirements:	1989-90	1990-91	1991-92	1992-93
Firm Sendout	27,650	28,329	28,484	28,731
Storage Refill:				
Underground	5,333	3,966	4,088	4,190
LNG Liquefaction	1,278	1,284	1,284	1,284
LNG Purchases	1,513	247	425	733
TOTAL	35,774	33,826	34,281	34,938
Resources:				
TGP CD-6	11,270	11,340	11,294	11,227
TGP NOREX	2,215	4,199	4,192	4,183
TGP Storage Return	53	30	30	31
Boundary	2,190	2,190	2,190	2,190
Iroquois/ANE	0	0	0	0
AGT F-1	15,234	15,171	15,169	15,166
AGT F-2	615	320	331	348
AGT F-3	1,338	1,338	1,338	1,338
AGT WS-1	250	250	250	250
AGT STB	8	0	0	0
PennEast CDS	0	6,206	6,206	6,206
LNG from storage	556	556	556	556
DOMAC LNG	706	711	711	711
Spot LNG Purchases	1,513	247	425	733
TOTAL	39,148	45,758	45,892	46,139
Interruptible Sales[2]:	3,374	11,932	11,611	11,201

Notes:

1. One BBtu is assumed to equal one MMcf.

2. These sales reflect the Company's present supply plans. The Siting Council recognizes that actual interruptible sales will vary as available supplies vary.

Source: Exhs. HO-SP-67, Table G-22D, page 2

TABLE 4

Boston Gas Company
Design Year Contingency Analyses
Heating Season
(MMcf)[1]

1. One Year Delay in PennEast CDS Project

Split-Year	Base Case Surplus (Deficit)[2]	PennEast CDS Contingency	Contingency Surplus (Deficit)[3]	Reserve
1989-90	135	0	135	0.2%
1990-91	667	3,271	(2,604)	(4.7)%[4]
1991-92	592	0	592	1.1%
1992-93	500	0	500	0.9%

Notes:

1. One BBtu is assumed to equal one MMcf.

2. See Table 2.

3. Contingency surplus (deficit) is derived by subtracting the supply contingency (column 3) from the base case surplus (deficit).

4. An action plan involving the use of firm propane purchases, increased utilization of firm contract gas and increased use of the Company's LNG facilities would allow the Company to meet the resource deficiency in the split-year 1990-91.

Source: Exh. HO-SP-67, Table G-23

TABLE 5

Boston Gas Company
Base Case Design Day Supply Plan
(MMcf)[1]

Requirements:	1989-90	1990-91	1991-92	1992-93
Firm Sendout	749.5	754.3	761.4	771.1
Resources:				
TGP CD-6	91.6	96.4	96.4	96.4
TGP NOREX	20.6	39.6	39.6	39.6
TGP Storage Return	13.0	13.0	13.0	13.0
Boundary	10.2	10.2	10.2	10.2
Iroquois/ANE	0	0	0	0
AGT F-1	127.1	127.1	127.1	127.1
AGT F-2	21.1	21.1	21.1	21.1
AGT F-3	6.3	6.3	6.3	6.3
AGT WS-1	37.9	37.9	37.9	37.9
AGT STB	29.8	29.8	29.8	29.8
AGT SS-III	10.3	10.3	10.3	10.3
PennEast CDS	0	29.0	29.0	29.0
LNG from storage	291.4	291.4	291.4	291.4
DOMAC LNG	103.3	103.3	103.3	103.3
Firm Propane	107.3	107.3	107.3	107.3
TOTAL	874.7	922.7	922.7	922.7
SURPLUS (DEFICIT):	125.2	168.4	161.3	151.6
RESERVE:	16.7%	22.3%	21.2%	19.7%

Notes:

1. One BBtu is assumed to equal one MMcf.

Source: Exh. HO-SP-67, Table G-23

TABLE 6

Boston Gas Company
Design Day Contingency Analyses
(MMcf)[1]

1. One Year Delay in PennEast CDS Project

Split-Year	Base Case Surplus (Deficit)[2]	PennEast CDS Contingency	Contingency Surplus (Deficit)[3]	Reserve
1989-90	125.2	0	125.2	16.7%
1990-91	168.4	29.0	139.4	18.5%
1991-92	161.3	0	161.3	21.2%
1992-93	151.6	0	151.6	19.7%

Notes:

1. One BBtu is assumed to equal one MMcf.
2. See Table 5.
3. Contingency surplus (deficit) is derived by subtracting the supply contingency (column 3) from the base case surplus (deficit).

Source: Exh. HO-SP-67, Table G-23

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 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 services 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 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. (See. 5, Chapter 25, G.L. Ter. Ed., as most recently amended by Chapter 485 of the Acts of 1971).