DECISIONS AND ORDERS

MASSACHUSETTS ENERGY

FACILITIES SITING COUNCIL

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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 Third and Fourth Supplements to the Second Long-Range Forecast of Natural Gas Resources and Requirements: 1985 through 1990	Docket No. 84-25

Final Decision

Susan F. Tierney
Hearing Officer
June 19, 1986

On the Decision:

Brian G. Hoefler

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The Energy Facilities Siting Council ("Siting Council") hereby APPROVES, subject to the CONDITIONS set forth herein, the petition of the Boston Gas Company and Massachusetts LNG, Inc. for approval of their Joint Third and Fourth Supplements to their Second Long-Range Forecast of natural gas resources and requirements.

I. INTRODUCTION

A. Background

Boston Gas Company ("Boston Gas" or "the Company") distributes and sells natural gas to residential, commercial and industrial customers in the City of Boston and 73 other Massachusetts communities. It is the largest distribution company in the commonwealth with about 500,000 customers and firm sendout of about 63,000 thousand dekatherms ("MDth")[1] during the 1984-85 split year. Boston Gas is the sole supplier of gas to the Wakefield Municipal Gas Company and exchanges gas with the Cambridge Division of Commonwealth Gas Company.

All of Boston Gas' capital stock is held by Eastern Gas and Fuel Associates ("Eastern"). Eastern also owns 36.8 percent of the outstanding stock of Algonquin Energy, Inc., the parent of Algonquin Gas Transmission Company ("Algonquin" or "AGT").[2] Algonquin is Boston Gas' largest pipeline supplier and is also the parent of Algonquin SNG, Inc., a supplier of substitute natural gas ("SNG") from naptha feedstock. Boston Gas purchases additional natural gas from Tennessee Gas Pipeline Company ("Tennessee" or "TGP"). Boston Gas' one subsidiary, Massachusetts LNG, Inc. ("Mass. LNG"), holds long-term leases on two liquified natural gas ("LNG") storage facilities. Since Mass. LNG makes no wholesale or retail sales of gas, the sendout data provided in the forecast and the Siting Council's review of those data are exclusive to Boston Gas. Boston Gas also owns 11.3 percent of the stock of Boundary Gas, Inc., a closely-held corporation formed to import natural gas from Canada.

The Boston Gas service territory is divided into nine operating divisions. Seven are supplied solely by TGP, one is supplied only by AGT and one is supplied by both pipeline companies.

B. History of the Proceedings

The Company's Joint Third Year Supplement to the Second Long-Range Forecast was filed at the Siting Council's offices on

1. One MDth equals one billion Btus ("BBtu") or roughly one million cubic feet ("MMCF") of natural gas.
2. In June 1986 Texas Eastern Transmission Corporation announced that it planned to buy all of the outstanding stock of Algonquin Energy, Inc. Previous to that announcement Texas Eastern owned 28 percent of Algonquin Energy.

October 3, 1984 ("1984 Supplement"). The "Notice of Adjudicatory Proceeding and Prehearing Conference" was published once per week for three consecutive weeks during October and November 1984 in the Boston Globe, the Boston Herald, the Middlesex News, the North Shore Sunday, and the Worcester Times. The Notice was also sent to the 74 cities and towns served by the Company, to seven libraries within the service territory, and to parties on the Siting Council's Adjudicatory Proceeding List. This Notice set the deadline for intervention in the instant proceeding as November 2, 1984, and it set the prehearing conference date for November 8, 1984.

On November 2, 1984, Distrigas of Massachusetts Corporation ("DOMAC") filed a "Petition to Intervene," the only such petition received in the proceeding. The prehearing conference was postponed pending resolution of DOMAC's intervention status.

Boston Gas filed its "Response of Boston Gas Company to Petition to Intervene of Distrigas of Massachusetts Corporation" on November 14, 1984. On November 21, 1984 DOMAC filed a "Memorandum of Distrigas of Massachusetts Corporation in Support of its Petition to Intervene." On November 30, 1984 the Company filed its "Response of Boston Gas Company to Memorandum of Distrigas of Massachusetts Corporation in Support of its Petition to Intervene." DOMAC subsequently filed its "Opposition of Distrigas of Massachusetts Corporation to Motion to Strike of Boston Gas Company," on December 12, 1984. The Hearing Officer granted DOMAC intervenor status on January 9, 1985, stating that DOMAC "may help to elucidate the issues ... and thereby aid the Siting Council in reaching a reasoned decision in the public interest on Boston Gas' Forecast Supplement."[3]

The prehearing conference was held on January 24, 1985. In the ensuing "Procedural Order," the Hearing Officer set dates by which Siting Council Staff ("Staff") and DOMAC had to issue their sendout and supply discovery questions. The Hearing Officer ruled that initially Boston Gas could not issue discovery questions to DOMAC but that Boston Gas could object to questions asked by DOMAC. The Order set the dates for the Company to file its responses to discovery as March 8, 1985 for sendout requests and March 1, 1985 for supply requests.

Staff and DOMAC issued their sendout discovery questions by the February 8, 1985 deadline. The Company filed a "Motion of Boston Gas Company to Quash Discovery by Distrigas of Massachusetts Corporation and for Stay of Procedural Schedual" on February 15, 1985. On February 25, 1985, DOMAC filed its "Response of Distrigas of Massachusetts Corporation to Motion of Boston Gas Company to Quash Discovery and for Stay of Procedural Schedule." The Hearing Officer denied the Company's motion in an "Order Denying Motion to Quash and for Stay of Procedural Schedule" issued on March 8, 1985. That Order also reset the filing date for DOMAC discovery requests to March 15, 1985.

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3. "Order Granting Intervention", at 2. Emphasis in original.

The Company filed its responses to Staff information and document requests on February 22, 1985 and its responses to Staff sendout discovery requests on March 8, 1985. The Company's responses to DOMAC discovery were filed on March 15, 1985. On March 22, 1985, DOMAC reported to the Siting Council that some of Boston Gas' information responses might be incomplete. However, DOMAC also reported an arrangement between itself and the Company to resolve any contested questions or responses. The Hearing Officer did not object to such an arrangement but requested a progress report on April 5, 1985. On April 5, 1985 DOMAC reported that the parties had made progress on most issues in the informal discussions. On April 12, 1985 Boston Gas filed written reponses on issues agreed to informally. The Hearing Officer requested a list from DOMAC on any outstanding data requests, and on April 19, 1985 DOMAC responded that only three issues remained contested. The Company filed its "Response of Boston Gas Company to Motion to Compel of Distrigas of Massachusetts Corporation" on April 26, 1985.

Since no decision on the pending forecast supplement had yet been issued, Boston Gas filed a request on May 23, 1985 to postpone the July 1, 1985 filing date for its 1985 forecast. The Hearing Officer agreed stating that the due date for the 1985 forecast filing would be established in the Siting Council's decision on the 1984 Supplement.

On September 20, 1985, the Siting Council issued its Notice of Inquiry into an Evaluation of Standards and Procedures for Reviewing Sendout Forecasts and Supply Plans of Massachusetts Natural Gas Utilities in Docket No. 85-64 ("NOI" or "Notice of Inquiry"). The purpose of the Notice of Inquiry was to solicit comments from all Massachusetts natural gas companies subject to the Siting Council's jurisdiction as to how the Siting Council's review process for gas company forecasts and supply plans could be made more effecient and effective, and its decisions on those forecasts and supply plans more meaningful. The NOI also set 1985 filing dates for gas companies, including Boston Gas. The Company was notified that its filing date would be Novmeber 1, 1985, that the filing need only consist of updated gas tables ("1985 Forecast"), and that review of the 1985 Forecast would be consolidated with review of the 1984 Supplement.

The Notice of Inquiry set forth a large number of specific suggestions for changes in the standards and procedures followed by the Siting Council in gas company forecast and supply plan proceedings. After requesting and receiving written comments on these suggestions from all the regulated gas companies, the Staff held 10 days of hearings on the Notice of Inquiry during November 1985. Boston Gas presented comments at the hearings on November 25, 1985 and answered numerous questions from the Staff regarding not only the issues raised in the Notice of Inquiry but also the contents of the forecasts themselves. While Boston Gas' witnesses did not testify under oath, they cast considerable light on certain aspects on the Company's sendout forecast methodology and supply planning process. The Company's responses during the hearings are referred to in this Decision as "Tr., November 25, 1985, at ___," and will be considered part of the record in this proceeding.

As stated in the Procedural Order of October 22, 1985 in Docket No. 85-64, the present Decision is made on the basis of the Siting Council standards and procedures which prevailed at the time the 1984 Supplement and 1985 Forecast were filed. However, certain applicable changes to those standards and procedures resulting from the Notice of Inquiry and the resultant Order in Docket No. 85-64 are discussed in Section VII., infra, along with suggestions and instructions for their implementation in the 1986 filing.

On November 1, 1985 the Company filed its gas tables updating the information contained in the 1984 Supplement. On May 15, 1986, Staff issued a final set of data requests. The Company's responses filed on May 29, 1986 complete the record for this proceeding.

II. PREVIOUS CONDITIONS

In its review of the Company's previous Forecast, the Siting Council approved the forecast subject to four conditions as follows:[4]

(1) That the Company correct the inconsistencies in its treatment of non-heating season temperature-sensitive load growth in its next filing. The Company should distinguish between temperature-sensitive load growth and decreases in temperature-sensitive consumption by existing customers during the non-heating season, and should document its assumptions. Moreover, if the Company implicitly assumes that conservation will occur, or if it accounts for conservation in its variable heating increment algorithm, the amount of rate of conservation [sic] should be stated explicitly.

(2) That the Company account for reduced consumption by existing customers in its next filing as shown by its meter-reading study, data base reports, and other data analyses or studies. The Company should state explicitly its source(s) of data for determining the reductions in consumption per customer and its judgements in interpreting the data. The Company should also describe in detail how forecasted reductions are allocated between the heating and non-heating seasons, between base load and temperature-sensitive load in each season, and between peak and off-peak degree-day intervals for temperature-sensitve load in each season. The Company should meet with Council Staff within ninety days to discuss compliance with this Condition.

(3) That the Company use all due diligence in all future negotiations to seek remedies that will reasonably reduce its costs and risks, such as reductions in its take-or-pay obligations, further reductions in its total Distrigas LNG volumes, or pursuit of other contractual remedies that will reduce the Company's LNG associated costs and risks. The Company shall document its efforts in compliance with this condition in its next Forecast.

4. 10 DOMSC 278, 340-341 (1984).

(4) That the Company discuss the most likely sources of LPA (or LNG) to which the Company would turn in the event of an LNG disruption, including names of suppliers, and estimates of the time required between initial contact and conclusion of the supply agreement. For supplies that arrive by ship, the Company should estimate the time required to ship LNG or propane from each supplier to the terminal; the Company's judgement as to whether propane deliveries can be terminalled at the Sea-3 facility in Newington in less than the 60 days required by the Sea-3 contract; and the number of trucks and frequency of truck trips required to bring propane to the Company's service area. For supplies that arrive by truck or rail, the Company should discuss the arrival point of the propane, the time required to transport propane from the source to the arrival point and the number of trucks and frequency of truck trips required to bring the propane to the Company's service area.

The Company addresses each Condition individually in Appendix A of the 1984 Supplement. The Siting Council discusses each of the Company's responses herein in the sections listed below.

Condition	Section of Discussion
1	IV.B.1.b. and IV.B.1.d.
2	IV.B.1.d.
3	V.C.3.
4	V.B.4.

III. SCOPE OF THE REVIEW

As part of its mandate to "provide a necessary energy supply for the commonwealth with a minimum impact on the environment at the lowest possible cost," the Siting Council reviews whether projections of gas requirements "are based on substantially accurate historical information and reasonable statistical projection methods."[5]

The Siting Council has previously found statistical projection methods to be "reasonable" if they are reviewable, appropriate and reliable. A forecast is reviewable if it contains enough information to allow a full understanding of the forecast methodology; a forecast methodology is appropriate if it is technically suitable to the size and nature of the Company; a methodology is reliable if it instills confidence that its data, assumptions and judgments produce a forecast of what is most likely to occur.[6]

5. M.G.L. c. 164, secs. 69H, 69J.
6. See Haverhill Gas Company, 8 DOMSC 48, 50 (1982); Bay State Gas Company, 9 DOMSC 129, 137 (1982); Commonwealth Gas Company, 9 DOMSC 332, 341 (1983); Colonial Gas Company, 10 DOMSC 1, 5 (1983); etc.

The Siting Council exercises broad discretion in its application of these criteria. To the extent that forecasts affect the Company's decisions to construct facilities, secure new supplies, design conservation programs, or formulate strategies for dispatching supplies within the constraints of existing facilities and contracts, the Siting Council reviews whether the Company's decisions in these areas are consistent with its mandate to provide a necessary energy supply at minimal environmental impact and lowest possible cost. As the Siting Council stated in its review of Boston Gas' 1981 Forecast, "Such thorough investigative actions are necessary to the review process and the authority to do so may be necessarily or reasonably inferred from the Council's enabling legislation."[7]

IV. FORECAST OF SENDOUT REQUIREMENTS

A. Forecast Methodology Description

1. Annual Forecast

Boston Gas' basic sendout forecast methodology as well as that methodology's evolution was described in detail in the two previous Siting Council decisions.[8] The methodology established in the 1982 forecast remains substantially the same in the latest filings.

The Company identifies the significant factors determining sendout as (a) gas supply and supplemental feedstock availability, (b) sendout temperature sensitivity, (c) marketing policies, (d) weather factors, and (e) economic factors.[9] These factors are analyzed in three sequential analyses to forecast sendout. First, the Company determines the current availability of annual gas supplies and allowable operating flexibility in terms of maximum daily quantities ("MDQ") of pipeline gas, gas storage capacity and return, and peak shaving capacity. Next, Boston Gas assesses the requirements of existing customers throughout the year, determines whether any supplies are available for additional sales, and, if so, establishes a target load growth rate. Third, a marketing strategy is designed to meet the target growth.[10]

To forecast existing demand and net load increase, Boston Gas first selects a system-wide target load growth rate. The Company then estimates the temperature sensitivity of that growth and whether it is expected to occur in the heating season or the non-heating season. Adding this information to the updated sendout totals from the previous year, the Company determines new base load factors and heating increments for each of the five forecast years. Since Boston Gas has determined that customer heating load reacts differently under varying weather conditions, the Company calculates different heating increments for six temperature ranges.[11] [12]

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7. 7 DOMSC 1, 18 (1982).
8. 9 DOMSC 1, 12-53 (1982); 10 DOMSC 278, 287-306 (1984).
9. 1984 Supplement, at 1.
10. 1984 Supplement, at 1.
11. See 9 DOMSC 1, 16 (1982).

Boston Gas uses the new baseload factors and heating increments as input to its gas dispatching model. The dispatch model combines these inputs with weather statistics and supply data to determine how best to meet daily sendout requirements in each forecast year. If necessary, the Company revises its load growth targets and runs the model again. Once the firm sendout requirements are satisfied, the dispatching model estimates interruptible sales under normal weather conditions. Finally, the Company computes the optimum number of customers and amount of load that may be added in each customer class to meet load growth and temperature sensitivity targets. The optimum load allocation is checked against market forecasts to ensure that the growth targets are reasonable. This process results in the sendout forecast summarized in Forecast Tables G-1 through G-5.

Table 1 below lists Boston Gas' most recent forecast of sendout requirements by customer class for the first and last years of the forecast period; Table 2 lists the annual growth and growth rates for normal and design year forecasted sendout.

TABLE 1

Forecast of Annual Sendout by Customer Class
Normal Year (MDth)

	1985-86		1989-90	
Class	Heating Season	Non-Heating Season	Heating Season	Non-Heating Season
Residential -- Htg	22,226	9,895	24,675	10,253
Residential -- Non-Htg	2,156	2,409	2,005	2,197
Commercial	13,136	6,987	16,709	7,562
Industrial	3,227	1,948	4,111	2,757
Wakefield	270	129	314	131
Company Use and UAF	4,640	782	4,846	746
Total Firm Sendout	45,655	22,150	52,660	23,646
Interruptible	0	35,117	0	10,463
Total Sendout	45,655	57,267	52,660	34,109

Source: 1985 Forecast, Tables G-1 through G-5.

12. The Company has found that, even though newly constructed homes are more energy efficient than older homes, the new homes tend to consume more gas annually because they tend to be larger than older homes. Response to Data Request SO-17.

TABLE 2

Normal and Design Year Firm Load Growth
(MDth)

Split Year	Normal Year Sendout	Normal Year Growth (Rate)	Design Year Sendout	Design Year Growth (Rate)
1984-85	65,305 *	----	----	----
1985-86	67,805	2,500 (3.8%)	73,629	----
1986-87	70,305	2,500 (3.7%)	76,322	2,693 (3.7%)
1987-88	72,305	2,000 (2.8%)	78,491	2,169 (2.8%)
1988-89	74,305	2,000 (2.8%)	80,660	2,169 (2.8%)
1989-90	76,305	2,000 (2.7%)	82,830	2,170 (2.7%)

* Normalized actual sendout

Source: 1985 Forecast, Table G-5.

Boston Gas has made a few modifications to this methodology since the last Siting Council decision. The Company has found that rather than using two-day moving averages to smooth both sendout and temperature data, the model fits the data better when only temperature data is smoothed on a two-day moving average basis.

One further change to the model is in the customer consumption patterns. During the past five years Boston Gas customers followed a pattern of increasing consumption per degree day ("DD") as DD level increases. However, during the 1983-84 heating season the pattern leveled off to a relatively constant consumption rate over all DD ranges. To compensate for this change in normal customer behavior yet still account for the historical increased consumption rate in the colder temperature ranges, the Company based its normalized heating increments on the 1983-84 split-year but retained the consumption patterns from the 1981-82 split-year for calculating design year heating increments.

2. Design Day Forecast

Boston Gas uses the same forecasting methodology for daily sendout as that for annual sendout -- a methodology based on correlation of daily sendout to a two-day moving average of DD. Since the Company's sendout is highly temperature sensitive, the design day forecast is based on an extrapolation to design conditions of the temperature-sensitive consumption rate for the 50+ DD heating increment. Boston Gas has established as its design day planning criteria the sendout necessary to satisfy demand on a 73 DD day as recorded by the National Weather Service at Logan Airport.[13] This DD level is the most recorded on a single day by the National Weather Service in Boston since 1923.

From this model Boston Gas forecasts the following design days over the forecast period:

TABLE 3

Forecast of Design Day Firm Requirements
(MDth)

Split Year	Forecasted Design Day Sendout	Design Day Growth (Rate)
1985-86	682.7	31.9 (4.9%)
1986-87	714.5	31.8 (4.7%)
1987-88	746.4	31.9 (4.5%)
1988-89	778.2	31.8 (4.3%)
1989-90	803.8	25.6 (3.3%)

Source: 1985 Forecast, Table G-5.

B. Forecast Methodology Analysis

1. Annual Forecast

a. Load Growth Assumptions

Current supply availability at the wellhead both domestically and in Canada and the efforts by TGP, AGT, and others to bring additional gas into New England has brought a cautious optimism to New England about partial relief from historical supply restrictions. These industry changes were a major topic in the Siting Council's NOI hearings during November 1985. At that time Boston Gas stated its opinion that due to the increase in supply options, the industry is transforming from a supply-driven (supply-constrained) market to a more dynamic, demand-driven market.[14] The recent decline in oil prices has placed additional downward pressure on natural gas prices and has contributed to the transition to a demand-driven market. The Siting Council believes a demand-driven gas market will benefit

13. A 73 DD day is a day in which the average of the high and low hourly temperatures equals -8'F.
14. Tr., Novmeber 25, 1985, at 195.

consumers by helping to reduce gas prices and increasing energy consumption options.

In response to this market shift, Boston Gas' 1985 Forecast sets its load growth targets at 2,500 MDth (3.8%) for the first two forecast years and 2,000 MDth (2.8%) for each year thereafter. These targets have increased from the anticipated annual growth of about 1,000 MDth in the 1984 forecast[15] and about 545 MDth annually in the 1983 forecast. The revised growth targets are result from the increased optimism about the availability of pipeline supplies, traditionally the factor limiting Boston Gas' growth potential.

While this market transition provides the Company with new opportunities to increase its sales, the transition also places new responsibilities on the Company to insure that cost/reliability tradeoffs are maximized and that load growth estimates are based on the limits of the market rather than the limits of supplies. The Siting Council believes that new efforts to forecast load growth are necessary. The Company has never totally explained how it selects its "growth targets" although presumably they are based on the difference between available supply and existing demand (with adjustments for uncertainties in both), management judgment of additional market demand, and financial goals. As supply (and therefore growth) restrictions are relaxed, Boston Gas could set its load growth targets much higher. Analyzing scenarios of over-forecasting or under-forecasting load growth is becoming increasingly important as growth targets increase. The effects of these scenarios on the adequacy of supply and on the economics of contracts and proposed facilities is important to the Siting Council, and we urge Boston Gas to begin developing plans to accurately forecast load growth in a demand-driven market.

The 1985 growth targets of about 3.8 percent are more ambitious than any forecasted by Boston Gas since the single year growth of 6.9 percent forecast in 1977 for the 1978-79 split-year. No Boston Gas forecast has predicted growth over five years as high as the 16.8 percent estimated in this year's forecast. The 1984 Supplement forecast growth in the first year of 606 MDth, and indeed the Company exceeded that growth with a normalized load increase of 739 MDth.[16] We ask that in its next forecast Boston Gas submit a comparison and analysis of its actual load growth during the 1985-86 split-year to the 2,500 MDth target in the 1985 forecast. This requirement is listed as part of Condition 1 in the summary of conditions at the end of this decision.

b. Temperature Sensitivity Assumptions

Over the forecast period Boston Gas allocates its total expected load growth to temperature-sensitive and non-temperature-sensitive categories as follows:

15. Except for the first forecast year, 1984-85, where growth was expected to be 606 MDth.
16. 1984 Supplement, Table G-5; 1985 Forecast, Table G-5.)

TABLE 4

Temperature Sensitivity of Load Growth

Type of Load	Heating Season	Non-Heating Season
Temperature Sensitive	68%	0
Non-Temperature Sensitive	14%	18%

Source: 1984 Supplement, at 30; Response to Data Request No. SO-2.

The temperature sensitivity of Boston Gas' load growth was a point of concern in the previous Siting Council decision.[17] In that decision we stated our concern about the Company accounting for temperature-sensitive growth during the heating season but not during the non-heating season even though it is well-known that temperature-sensitive load growth also occurs during the non-heating season. We noted that although "the magnitude of the inconsistency is small ... inconsistent treatment of load growth diminishes the level of confidence that can be accorded to the Company's forecast."[18] We suspected that the method for allocating temperature-sensitive load might be introducing biases into the forecast, overstating heating-season load growth and perhaps overstating peak day growth. We suggested sensitivity studies as better ways to address these variations in temperature-sensitive requirements.

Condition 1 in that decision[19] ordered Boston Gas to correct the inconsistencies in the allocation of its temperature-sensitive load and state its treatment of conservation in its variable heating increment algorithm. The Company responded by saying that no measurable temperature-sensitive load growth has been detected in the non-heating season. Even if it did occur in the non-heating season, the Company noted, it would only decrease interruptible sales.[20]

The Siting Council emphasizes that Boston Gas is preparing a <u>forecast</u> and therefore should be using its data resources and staff expertise to their maximum extent to <u>predict</u> sendout over the next five years. Any factors that are likely to occur should be considered to the extent possible so as to increase confidence that the most likely event has been forecasted. To ignore factors that are likely to occur, whether large or small, introduces biases into the forecast that decrease both the accuracy of the Company's forecast and the Siting Council's confidence that the best assumptions, data, and methodology have been used. While the Siting Council does not expect

17. 10 DOMSC 278, 289 (1984).
18. 10 DOMSC 278, 291 (1984).
19. Conditions from the previous Siting Council decision are listed in Section II, <u>supra</u>.
20. 1984 Supplement, Appendix A, at 1.

the Company to spend a lot of time trying to forecast factors known to be of little or no significance, the Siting Council believes that Boston Gas could easily estimate the temperature-sensitive load growth in the non-heating season.[21] The Company has rejected the Siting Council's request to estimate this load growth and include that growth in its forecast presumably because it cannot be determined with statistical significance. We suggest that Boston Gas find a reasonable way to forecast non-heating season temperature-sensitive load.

c. Changes in Usage by Existing Customers

The Company accounts for many changes that have occurred in its existing customer base by adjusting its springboard baseload and heating increments for the latest sendout data. Updating these data is a necessary and important part of the forecast since it captures load changes actually experienced. However, the Company continues to confine its forecast to updating its baseload and heating increments and adding target load growth -- forecasting changes in its existing customer base is minimal. We reiterate our belief that a sendout forecast is meant to forecast the most likely sendout level. We do not see how the Company can forecast the most likely sendout without forecasting changes in existing customers' load patterns.

In past decisions the Siting Council has asked Boston Gas to forecast changes in its existing customer base.[22] Even though the Company measured conservation of 1.5 percent/year over the previous four years[23], Boston Gas has resisted making forecast changes for conservation because it does not believe it can reliably forecast future conservation.[24] Additionally, the Company notes its primary responsibility to meet peak load requirements of existing firm customers during the temperature ranges where the least data are available and the least conservation observed. Thus, as a conservative measure, the Company factors no conservation (nor any other consumption changes) into its existing customer base.[25]

The Siting Council and its Staff have suggested a more appropriate way to address forecast uncertainties: sensitivity analysis.[26] If Boston Gas has identified uncertainties in its forecast then it should conduct rigorous sensitivity analysis to analyze the effects of fluctuations in the forecast's primary explanatory variables. From that analysis an appropriate safety factor should be determined and applied to the most likely sendout

21. We note that the 1984 forecast of heating season requirements was right on target while the non-heating season requirements were under-forecast by 133 MDth. Perhaps the considration of temperature-sensitive load during the non-heating season would have reduced that 133 MDth difference. 1984 Supplement, G-5; 1985 Forecast, G-5.
22. 9 DOMSC 1, 38 (1982); 10 DOMSC 278, 299 (1984).
23. 1984 Supplement, at 28.
24. 1984 Supplement, at 29, and Appendix A, at 3.
25. 1984 Supplement, at 28.
26. 10 DOMSC 278, 291 (1984); Minutes of Meeting on Condition 2, May 8, 1984.

level thereby defining the supply reserve necessary to adequately address design requirements. By that means the Company will have much better control of the level of conservation (or any other uncertainties) built into the forecast enabling better understanding of both the reliability and the economics of the forecast.[27]

The Siting Council also suggests that there may be a flaw in the Company's methodology if a reason to disregard conservation on an annual basis is because conservation cannot be reliably determined on peak days.[28] This area requires further analysis and discussion before any orders are made or actions taken.[29]

d. Changes in Usage by Existing Customers -- Compliance with Previous Conditions

In its response to the second part of Condition 1 of the previous Siting Council decision, Boston Gas states that it cannot incorporate factors like conservation into the forecast until they persist "over a reasonable period of time."[30] The Company estimates conservation at 1.5 percent/year yet does not factor it into the sendout forecast other than to the extent that heating increments are updated to reflect any conservation experienced during the previous year.[31] The Siting Council asked Boston Gas to report any conservation built into the heating increments and to that end the Company has complied with Condition 1.

Condition 2 of the previous decision ordered Boston Gas to account for reduced consumption as detected by various analyses and studies, to detail any assumptions and judgments, and to describe the methodology for distributing conservation throughout the forecast. Soon after that decision was issued, the Company met with Staff to discuss compliance with this condition. The Company recounted a variety of reasons why results from on-going conservation monitoring projects should not yet be applied in the sendout forecast. Staff agreed that compliance with this condition would be satisfied by further documenting current studies and updating their status. The Company dutifully complied in its 1984 Supplement.

Since the Siting Council is still concerned with the effects of conservation on sendout forecasting, we reinstate Condition 2 from the previous decision as Condition 2 of this decision. We have acknowledged the struggles of the Company to identify, quantify and

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27. The Siting Council notes that this type of planning is very similar to the Company's analysis of uncertainties surrounding the interruption of LNG ship deliveries. See discussion in Section VI.A.2., <u>infra</u>.
28. 1984 Supplement, at 28.
29. The methodological differences between annual and peak day forecasts should be a major area studied in the survey and evaluation ordered in Section III.C., <u>infra</u>.
30. 1984 Supplement, Appendix A, at 2.
31. 1984 Supplement, at 28 and Appendix A, at 1; Tr., November 25, 1985, at 69.

reliably estimate conservation through many ongoing studies.[32] Thus, as agreed during the previous adjudication, compliance with this condition may be satisfied by carefully documenting current studies, updating their status, and providing an estimate of when the results will be ready for application in the Company's forecast.

e. Calculation of Base Load Factors and Heating Increments

In the Siting Council's 1982 decision, Condition 4 required Boston Gas to update its base or "springboard" heating increments to reflect new information about changing customer use patterns.[33] The Company dutifully complied in its 1983 forecast, and in our 1984 decision we stated our satisfaction that the Company complied with the Condition.[34] The 1984 Boston Gas Supplement again adjusted the springboard heating increments to account for changing customer use characteristics. The Siting Council appreciates the Company's efforts to keep its heating increments up to date and hopes the Company will continue to do so.

In the 1984 Supplement the Company reported its finding that customer consumption patterns had deviated from those of the previous five years. Instead of an increasing rate of consumption per DD as daily DDs increase, the 1983-84 heating season customers consumed gas at a relatively constant rate per DD over all DD ranges. Normalizing the 1983-84 heating season sendout to account for relatively constant consumption resulted in an estimated normal sendout 4.8 percent below that anticipated in the 1983 forecast. Thus, Boston Gas found it necessary to include these new data in its 1984 (and 1985) normal year sendout forecast. However, in the Company's judgment, the consumption patterns of the 1981-82 year better reflect the patterns of design conditions and therefore design year calculations are based on the patterns of that year.[35]

One possible explanation for the relatively constant consumption, the Company hypothesizes, is that "customer behavior, (i.e. implementation of temporary conservation measures) was fairly consistent during this season" although under design conditions "customer behavior negates the effects of permanent conservation measures." As a conservative measure, "The Company provides for the possibility that the forces behind the overestimation will continue to act during the forecast period by incorporating the potential for volatile changes in consumption."[36]

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32. The Company is conducting a variety of conservation studies. Specific areas discussed and reported during this proceeding included the Company's meter-reading study, conservation database reports, appliance saturation survey, price elasticity/econometric model analysis, annual load analysis, seasonal weather pattern analysis, variable heating increment model, and Mass-Save, Inc. data.

33. 9 DOMSC 1, 111 (1982).

34. 10 DOMSC 278, 292 (1984).

35. 1984 Supplement, at 25.

36. Response to Data Request No. SO-5.

The normal and design heating increments of the 1984 forecast are compared in Table 5.

TABLE 5

1984 Springboard Baseload Factors and Heating Increments
Heating Season: Normal vs. Design

Forecast	Baseload Factor	Heating Increment Degree-Day Ranges					
		0-10	10-20	20-30	30-40	40-50	50+
Normal	64.339	7.540	7.540	7.240	7.330	7.340	7.290
Design	64.490	6.980	6.980	7.630	7.460	7.860	7.860

Source: 1984 Supplement, at 25 and 26.

The Siting Council commends the Company for continuing to monitor consumption rates and include new information in its forecast. We believe the Company used prudence in its design year planning by waiting to see if the 1983-84 consumption patterns reflect a permanent shift in consumption patterns, a difference in consumption between two different types of temperature patterns, or a consumption abnormality. With the passage of the 1984-85 and 1985-86 heating seasons the Company should have a better understanding of the significance of the new consumption rates. We urge the Company to comment on its findings in its next filing.

2. Design Day Forecast

Boston Gas estimates its design day (peak day) forecast with the same heating increment function as that used for the annual forecast. These heating increments are based on daily sendout correlated to a two-day moving average of DD, the factor often cited as the major influence on sendout in regions of temperature sensitivity.

Boston Gas has presented little individual analysis of design day to the Siting Council. Discussion of design day has been primarily in terms of the annual forecast -- since the methodologies are the same, a discussion of the annual forecast methodology is necessarily a discussion of the design day methodology. The Siting Council believes supplying design day is a major reliability and least-cost planning responsibility. It is the day where risk of sendout exceeding supply is greatest and where expensive peak shaving measures are most necessary. Design day sendout is expected to grow by 153 MDth (23.5%) over the five-year forecast period.[37] Given this high level of growth and the severity of the penalties for either

37. This growth contrasts with design year growth of 16.8 percent over five years indicating increasing temperature sensitivity.

under-forecasting or over-forecasting design day, Boston Gas should be devoting significant resources to forecasting design day as accurately as possible.

We believe Boston Gas needs to closely examine its design day forecasting methodology. In Section IV.C., infra, the Siting Council asks the Company to re-evaluate many of its present assumptions. As part of that evaluation, the Siting Council expects Boston Gas to determine whether or not it is appropriate to use the same methodology to forecast annual and peak day sendouts.

For its next forecast filing, we ask the Company to compare actual normalized peak day growth for the 1985-86 split year with the 31.9 MDth estimated in the 1985 forecast. This requirement is listed as the second part of Condition 1.

C. Conclusions

1. Review Standards

The Siting Council has commended Boston Gas in the past for its efforts in producing a coherent, reviewable forecast and for its commitment to improving forecast reliability by exploring new methodologies.[38] We noted in our 1982 decision that "the high standard of reviewability of the current submission allows us to address the appropriateness and reliability of the forecast in greater detail."[39] Even though Boston Gas' initial filing did not contain all of the back-up data requested in our last decision,[40] for the most part the same holds true today: Boston Gas continues to submit forecasts commendable for their reviewability, allowing the Siting Council to concentrate its review process on its appropriateness and reliability standards.

The Siting Council believes that appropriateness and reliability are distinct but closely related. A methodology is appropriate for a particular company if the forecast sophistication matches the resource level of that company and helps it to reliably optimize decisions regarding facilities expansion or abandonment, long-term supply planning, and short-term dispatching. Appropriateness necessarily varies with the size and nature of gas companies but reliability does not -- forecast reliability must be

38. 4 DOMSC 50, 60 (1980); 9 DOMSC 1, 15 and 53 (1982); 10 DOMSC 278, 306 (1984).
39. 9 DOMSC 1, 15 (1982). Emphasis in original.
40. The Siting Council requested that Boston Gas submit with its initial filing base load factors and heating increments, a sample calculation showing how those factors and increments are updated, peak load estimates by division, load growth targets, and end-use assumptions for allocating load growth by customer class. 10 DOMSC 278, 286-7 (1984). Of these five back-up data requests, only base load factors and heating increments, and load growth targets were submitted in the initial filing. The other data were eventually obtained through discovery. See responses to Data Requests SO-1 and SO-2.

judged on its ability to predict the most likely sendout levels such that major supply decisions are optimized.

This optimum reliability level is reached when the costs of further methodology or data improvements are greater than the benefits of improving the forecast. Costs outweigh benefits when further methodology refinement would not change the outcomes of decisions based on the forecast. Alternatively, the optimum reliability is reached when random errors (e.g., weather or other unpredictables) are the major source of forecast error. If the methodology is refined to this point, sensitivity studies must be conducted to quantify the magnitude of forecast uncertainty due to random errors, as well as to help a company strategically plan to meet its firm customers' requirements in the event that identifiable but unlikely circumstances occur during the forecast period.

2. Forecast Methodology Evaluation

In the Siting Council's recent decision in Docket No. 85-64 on the NOI, the Siting Council acknowledged the close relationship between the appropriatness and reliability of a methodology when it divided the commonwealth's gas companies into three size categories. The category of large gas companies (which includes Boston Gas) is encouraged to work with Siting Council Staff "aggressively to pursue enhancements to forecasting techniques."[41]

In accordance with this intent, the Company is directed to work with our Staff to evaluate the appropriateness of the present forecast methodology in terms of its contributions to helping the Company plan reliable supplies. The Siting Council envisions an evaluation whereby all major underlying forecast assumptions, parameters, and judgments are analyzed on the basis of appropriateness, foundation in theory, historical reliability, and risks imposed on supply planning decisions. Such evaluation should include, but not be limited to, supply constraints, weather analysis, model selection (both annual and design day), end-use characteristics, load growth, and demographic/economic assumptions.

As an integral part of the evaluation, the Siting Council directs 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. Boston Gas should use the results of this survey as a reference for evaluating its own assumptions, data, and methodology. Upon completion of the survey and evaluation, Boston Gas should prepare a report 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. The report should include the distribution company survey. This order is listed as Condition 3 in the summary of conditions.

41. See Docket No. 85-64, at 9-10.

Realizing that the next forecast submission is less than three months away, Boston Gas can hardly be expected to complete or even make substantial progress on such a survey and evaluation before the Company's next filing. Therefore, we do not expect the report to be submitted in the September 1986 filing nor do we expect that filing to be greatly influenced by the above survey and evaluation. However, we do expect the Company to meet with our Staff and begin exploring plans to accomplish this evaluation, and we request a progress report in the next filing outlining all the issues to be studied and the schedule for completing the evaluation.

V. RESOURCES AND FACILITIES

Boston Gas purchases pipeline natural gas from Algonquin Gas Transmission Company and Tennessee Gas Pipeline Company under a variety of contracts. The Company also has arrangements with each pipeline and with various storage companies to inject pipeline gas into underground storage facilities during the summer for delivery during the following winter. Boston Gas supplements its pipeline supplies with purchases of propane from Dorchester Sea-3 Products, Inc. ("Sea-3") and with its remaining Distrigas of Massachusetts Corporation liquified natural gas inventories. In addition, the Company operates a network of facilities to store its own gas, LNG, and propane, to vaporize LNG into its distribution system, and to produce propane-air for injection into its distribution system. Finally, the Company maintains a substitute natural gas facility in Everett, Massachusetts that produces pipeline-quality gas from propane.

Tables 6 and 7 summarize the Company's supply contracts, storage capacity, and daily deliverability from pipeline suppliers and peak-shaving facilities.

TABLE 6

Boston Gas Supply Contracts

Supplier	Contract	Transporter	AVL (MDth/Yr)	MDQ (MDth/Dy)	Contract Period
Existing Supply Contracts:					
Algonquin	F-1	Algonquin	34,306	127.1	Through 10/89
	* WS-1	Algonquin	2,894	48.2	Through 11/87
Tennessee	CD-6	Tennessee	24,308	96.2	Through 11/00
	** CD-6	Tennessee	34,424	136.0	Through 11/00
DOMAC	*** LNG	Ship	13,746	66.6	Through 12/97
New Supply Contracts:					
Consolidated	F-2	Algonquin	7,809	21.4	11/86 - 10/09
Nat'l Fuel	F-3	Algonquin	2,312	6.3	11/86 - 10/09
Algonquin	F-4	Algonquin	3,387	9.1	11/85 - 10/86
TransCanada	Boundary	Tennessee	3,832	10.5	11/89 - 10/97
Abandoned Supply Contracts:					
Algonquin	SNG-1	Algonquin	0	0.0	Aband Pending ****
Other Transportation Contracts:					
Sea-3	Propane	Truck	4,587	37.2	Leased Each Winter
Penn-York Honeoye Consolidated	Firm Storage Return	Tennessee	1,779	12.7	Through 3/95

* 146 MDth of the WS-1 contract extends through 1989.

** Proposed increase in Tennessee's CD-6 AVLs and MDQs (See Tennessee Gas Pipeline Company, FERC Docket No. CP84-441).

*** Uncertainty currently surrounds the DOMAC delivery schedule. See Section V.C.3., infra.

**** Algonquin has filed an "Abbreviated Application of Algonquin Gas Transmission Company for an Order Authorizing Abandonment of Service Pursuant to Section 7(b) of the Natural Gas Act", Algonquin Gas Transmission Company, FERC Docket No. CP86-407, ("Abbreviated Application") at FERC seeking termination of its contractual obligations to supply SNG. Before the Abbreviated Application was filed Boston Gas had already negotiated total reduction in SNG purchases.

Sources: 1984 Supplement; 1985 Forecast; Responses to Data Requests S-1 through S-8.

TABLE 7

Boston Gas Storage Contracts and Facilities

Storage Ownership	Contract	Transporter	Capacity (MDth)	Max Withdrawl/ Vaporization Rate (MDth/Dy)	Contract Period
Storage Services:					
Algonquin	STB	Algonquin	3,500	29.7	Through 4/00
	S-IS	Algonquin	842	8.1	Termin. 6/86
	SS-III	Algonquin	1,064	10.1	Through 4/06
Penn-York		Tennessee	877	5.8	Through 3/95
Honeoye		Tennessee	800	6.0	Through 3/94
	*	Tennessee	960	6.0	Through 3/94
Consolidated		Tennessee	102	0.9	Through 3/00
Boston Gas		In Service Area	0.3	0.1	
LNG Storage:					
Boston Gas		In Service Area	2,140	129.8	
DOMAC		In Service Area	643	66.6	Through 12/97
Industrial Nat'l Leasing Corp. **		In Service Area	2,000	72.6	Through 6/97
Algonquin LNG		Truck ***	400	4.3	Through 5/92
Propane Storage:					
Sea-3		Truck	4,587	66.1	Through 4/87
Boston Gas		In Service Area	179	112.9	

* Proposed increase in Honeoye storage by 1986-87.

** Boston Gas leases LNG tanks in Salem and Lynn, Massachusetts, through its subsidiary, Mass. LNG.

*** LNG stored in Algonquin's Providence, Rhode Island tank could also be vaporized and returned by Algonquin pipeline if sufficient capacity is available, or by exchange with Providence Gas Company for DOMAC LNG.

Sources: 1984 Supplement; 1985 Forecast; Responses to Data Requests S-1 through S-8.

A. New Supply Projects

1. CONTEAL

Rate schedules for the CONTEAL project[42] were approved by the Federal Energy Regulatory Commission ("FERC") on June 18, 1984. The project includes Boston Gas' purchase of natural gas from Algonquin under the F-2 and F-3 rate schedules from November 1, 1986 through October 31, 2009. In the F-2 contract Algonquin will sell gas purchased from Consolidated Gas Supply Corporation ("Consolidated"); in the F-3 contract Algonquin will sell gas purchased from National Fuel Gas Supply Corporation ("National Fuel").

Under the contracts, Boston Gas' maximum daily quantity ("MDQ") of F-2 deliveries is 21.4 MDth, and its MDQ of F-3 deliveries is 6.3 MDth. Both rate schedules require Boston Gas to take at least 50 percent of the annual volumetric limit ("AVL"). To receive F-2 supplies Boston Gas must pay demand charges to Consolidated, Texas Eastern Transmission Company ("Texas Eastern" or "TETCO"), and Algonquin, plus a winter-requirements charge to Consolidated. To receive F-3 supplies the Company pays demand charges to National Fuel, Transcontinental Pipeline Company ("TRANSCO"), and Algonquin and also pays a winter-requirements charge to National Fuel. Table 8 summarizes the contract provisions.

TABLE 8

Boston Gas F-2 and F-3 Contract Provisions

	F-2	F-3
Maximum Daily Quantities	21.4 MDth	6.3 MDth
Annual Volumetric Limit	7,809 MDth	2,312 MDth
Minimum Annual Take (50%)	3,904 MDth	1,156 MDth
Total Demand Charge	$5,550,000/Yr	$2,030,000/Yr
Commodity Charge *	$3.80/MMBtu	$3.735/MMBtu

* F-2 rates as of January 1, 1985; F-3 rates as of February 1, 1985.

Source: Response to Data Request S-1.

42. The CONTEAL project was described in the Siting Council's previous Boston Gas Decision. See 10 DOMSC 278, 316 (1984).

2. Algonquin F-4

Recently Algonquin offered its customers a new baseload service under FERC Rate Schedule F-4.[43] Since Boston Gas found it did not need additional baseload supplies from Algonquin, it did not arrange for long-term F-4 deliveries.[44] However, Boston Gas contracted for F-4 gas during the development period of December 31, 1985 through October 31, 1986, apparently as an interim supply while awaiting the arrival of CONTEAL volumes scheduled for November 1, 1986.

3. Canadian Gas

Since the Siting Council's last Boston Gas decision there have been numerous developments with respect to the transportation of Canadian gas to U.S. markets. Most of the developments have been in response to increased efforts by producers and pipeline companies to market surplus Canadian gas in regions where pipeline capacity is under-utilized or in regions where gas markets are under-developed. The Northeast is generally viewed as an under-developed gas market due to the historical pipeline supply restrictions. Thus, a flurry of proposals have been submitted to FERC to introduce new supplies into the Northeast. As a result, there have been so many proposals to supply the same markets that FERC has not issued its approval to any one of them.[45]

a. Old Issues: Boundary, Trans-Niagara, Sable Island

Three Canadian gas projects of interest in New England are the Boundary Gas project ("Boundary"), Algonquin's C-1 project ("C-1" or "Trans-Niagara"), and the Sable Island project. Boston Gas has plans to secure long-term Canadian supplies through Boundary Gas, Inc., a joint venture of Northeastern gas distribution companies formed for the sole purpose of importing Canadian gas. Boundary volumes would be provided at the border by TransCanada PipeLines, Ltd. ("TransCanada") and transported domestically by the proposed Niagara Interstate Pipeline System ("NIPS")[46] and TGP. The C-1 volumes would also be delivered to the border by TransCanada and moved south by NIPS but would be transported into New England by Texas Eastern and Algonquin. The Sable Island project would transport gas from offshore Nova Scotia wells to the New England states through a proposed new pipeline known as the New England States Pipeline ("NESP").[47]

We noted in our last decision that "having observed how the

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43. See <u>Algonquin Gas Transmission Company</u>, FERC Docket No. CP84-654.
44. Although Boston Gas is not seeking new baseload supplies on the Algonquin side of its system, it is actively seeking new supplies on the Tennessee side. See Sections V.A.3. and V.A.4. <u>infra</u>.
45. Since these FERC proceedings are only of peripheral interest to the Siting Council and Staff in the instant case, no attempt will be made here to describe all the proposals.
46. NIPS is a joint venture of TGP, TRANSCO, TETCO, and TransCanada.
47. NESP is a joint venture of TETCO, TRANSCO, AGT, and NOVA - An Alberta Corporation.

Canadian gas projects have changed over the previous year, ... further changes in the volumes, prices and delivery schedules may be ahead."[48] As anticipated, there have been many changes. In our last decision we reported Boston Gas' expectation of receiving Boundary volumes by November 1985 and C-1 volumes by November 1986.[49] Boston Gas' 1984 Supplement moved both of those dates to November 1988, and its 1985 Forecast again revised the dates -- Boundary was rescheduled for delivery beginning November 1989 and C-1 was removed from the five-year forecast altogether.

The primary cause of delivery delays seems to have been the delays in constructing adequate transportation facilities between TransCanada and Tennessee/Texas Eastern (i.e., building the NIPS facilities). Boundary volumes were divided into Phases I and II where Phase I volumes would be transported by available pipeline capacity and Phase II volumes would require new capacity. Thus, Phase I participants began receiving Boundary gas beginning in November 1984 while Phase II participants (including Boston Gas) awaited the construction of NIPS. However, NIPS withdrew its FERC application in May 1986. The effects of this withdrawl on the Boundary and C-1 schedules, volumes, and prices are not yet clear. Still, the Company states in reference to volumes and prices that it "has not formally purchased future C-1 or Boundary volumes and has the opportunity to restate their needs."[50] Apparently the Company will not have to commit itself to Boundary and C-1 volumes (and prices) until Tennessee and Texas Eastern commit themselves to building the facilities to transport those volumes. We urge the Company to update the status of both the Boundary and C-1 projects in its next filing.

The 1984 Supplement and 1985 Forecast made no mention of Sable Island gas but presumably this project has been postponed due to the surplus of presently available domestic and Canadian supplies, the relatively low price of gas, and the high cost of building NESP, a new 360-mile long pipeline. Apparently Algonquin and Tennessee have signed precedent agreements with Sable Island gas suppliers, but any deliveries are not expected until at least 1991.[51]

b. New Issues: INGS

The primary cause of delays in moving Boundary and C-1 volumes to Massachusetts has been the delay in arranging transportation. In an effort to provide temporary service while FERC sorts through the various Northeast proposals, TGP filed an application at FERC to provide interim natural gas service ("INGS") for eleven distribution companies that are currently awaiting their Boundary volumes.[52] However, this application requires new TGP compression and pipeline

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48. 10 DOMSC 278, 316 (1984).
49. 10 DOMSC 278, 315 (1984).
50. Response to Data Request S-3.
51. Response to Data Request S-3.
52. Three of these companies are located in Massachusetts including The Berkshire Gas Company, Essex County Gas Company, and Fitchburg Gas & Electric Light Company. See Tennessee Gas Pipeline Company, FERC Docket No. CP86-251.

facilities including 5.4 miles of 30-inch pipeline in the vicinity of Monson, Massachusetts.

An amendment to that application adds two more companies, including Boston Gas, to the list seeking interim service. However, the amendment also proposes another 10.3 miles of pipeline construction in the areas of Oxford, Burlington, Reading, and Leominster, Massachusetts.[53] If all of these facilities are quickly approved and constructed as planned, TGP believes Boston Gas could expect delivery of 10.7 MDth/Day (3,914 MDth/Yr) by November 1986 on an interim basis until Boundary volumes are available. It remains to be seen whether such construction and transportation arrangements can be completed on such a rapid schedule. We ask Boston Gas to inform us in its next filing of the status of these supplies.

4. New Tennessee AVLs and MDQs

Tennessee has offered its customers the opportunity to increase their AVLs and MDQs under TGP's CD rate schedule ("AVL Docket").[54] Boston Gas is interested in obtaining more supplies on the Tennessee side of its system and therefore signed a precedent agreement in January 1985 to gradually increase its AVL from the present 24,308 MDth/Yr to 34,424 MDth/Yr by the 1987-88 contract year. The MDQ would increase from 96.2 MDth/Day to 136.0 MDth/Day. The Company believes an increase in CD-6 volumes will better serve its market segment in the areas served by TGP and will also reduce peak shaving requirements.[55]

In the INGS application Tennessee states that the demand originally projected in the AVL Docket will not materialize in 1987, and therefore the expected delivery date of the additional volumes has been delayed beyond 1987.[56] The INGS application did not provide a new estimate of when those volumes would be available.

B. <u>New Storage and Transportation Arrangements</u>

1. S-IS/SS-III

One of the Company's arrangements for underground storage and transportation of pipeline gas, Algonquin's S-IS storage and return service, expires in June 1986. Boston Gas indicates that Algonquin is following the S-IS service with a new storage service under FERC rate schedule SS-III beginning April 1986.[57]

Under the proposed SS-III service, Algonquin will provide

53. See <u>Tennessee Gas Pipeline Company</u>, FERC Docket No. CP86-251-001. The Siting Council has been an active intervenor in the INGS docket to assure that the commonwealth's concerns on environmental issues are adequately addressed.
54. See <u>Tennessee Gas Pipeline Company</u>, FERC Docket No. CP84-441-003.
55. Response to Data Request S-2.
56. See <u>Tennessee Gas Pipeline Company</u>, FERC Docket No. CP86-251, Exhibit H.
57. 1984 Supplement, at 6.

Boston Gas with 1064 MMcf of underground storage and will provide return service of up to 10.1 MDth/day as long as total volumes stay within the F-1/WS-1 MDQ's. Storage return above the F-1/WS-1 MDQ's will be on a best-efforts basis.[58]

2. Honeoye

Boston Gas has a contract with Honeoye Storage Corporation ("Honeoye") to store gas in the summer and withdraw it during the winter heating season. The Company indicates that it plans to increase its Honeoye storage capacity from the initially contracted volume of 800 MDth to 960 MDth by the 1986-87 heating season.[59] Since the contract withdrawl rate of 6.0 MDth/day will remain unchanged, the additional storage volumes will presumably be returned by extending the required number of days of TGP storage transportation.

3. TGP Firm Transportation Service

In its 1984 Supplement Boston Gas indicated that TGP filed a FERC application for authorization to provide firm transportation for returning storage volumes. For Boston Gas such a service would firm up present best-efforts transportation of its Consolidated, Honeoye, and Penn-York Energy Corporation ("Penn-York") storage volumes.[60] Boston Gas initially anticipated that the firm service would begin with the 1986-87 heating season at an MDQ of 15 MDth per day. However, later estimates indicated the service would be offered in the 1985-86 heating season and reviced the daily capacity estimates to 12.3 MDth/day and finally 12.7 MDth/day.[61] The final rate of 12.7 MDth/day was chosen because it corresponds to the total daily withdrawl rates for the Company's storage contracts with Consolidated, Honeoye, and Penn-York.

The Siting Council believes Boston Gas' new firm storage return transportation arrangements add an important new winter supply service. The ability to rely on delivery of an extra 12.7 MDth of pipeline gas during peak periods means Boston Gas will not have to use (or at least contract for) an additional 12.7 MDth of supplemental supplies. The Siting Council encourages Boston Gas to continue its efforts to secure competitively priced winter service contracts that can displace expensive peak shaving gas.

4. Sea-3 Propane Storage

In the Siting Council's last decision, Condition 4 asked Boston Gas to explain how it planned to provide backup propane in the event of an LNG supply disruption.[62] We were aware of the Company's contract to terminal propane at Dorchester Sea-3 Products' liquified

58. Response to Data Request S-4.
59. 1985 Forecast, Table G-24.
60. 1984 Supplement, at 17.
61. Response to Data Request S-5; 1985 Forecast, Table G-22.
62. 10 DOMSC 278, 339 (1984).

petroleum gas ("LPG") facility in Newington, New Hampshire, so we requested more information on the logistics of using that supply. Boston Gas' 1984 Supplement addressed that condition in Appendix A.

Boston Gas' agreement with Sea-3 is for winter terminalling of up to 50 million gallons (4,587 MDth) of propane at the Newington LPG tank. Sea-3 maintains a 400,000-barrel LPG tank[63] in Newington capable of receiving ships with capacities of up to 250,000 barrels (10.5 million gallons). Sea-3 can unload a 250,000-barrel ship into its tank in less than two days, and Boston Gas may withdraw its propane at rates up to 720,000 gallons/day (66.1 MDth/day) for transportation by truck or barge, and at rates up to 180,000 gallons/day (16.5 MDth/day) for transportation by rail car.[64]

Since the Company expects to move all propane by truck, it leases 10 propane trucks each winter dedicated to moving propane to Boston. These ten trucks can move about 405,000 gallons of propane per day, an amount somewhat less than the Newington truck withdrawl capacity of 720,000 gallons/day.[65] Trucking 720,000 gallons/day at the Company's estimated trucking rate of 40,500 gallons/truck/day would require 18 trucks. The Company states that it may arrange for additional trucks, if necessary, to increase the daily quantities transported.[66] Table 9 summarizes the capacity arrangements for Sea-3 propane delivery.

The factor limiting Sea-3 propane peaking capacity appears to be the Company's ability to truck propane from Newington to Boston. Although the Company believes it can use 10 trucks for 30 consecutive days to transport about 12 million gallons (1,100 MDth) of propane,[67] it seems improbable that 10 trucks could operate 24 hours per day for thirty days straight with 100 percent reliability. The additional trucking capacity alluded to in the 1984 Supplement might be necessary just to maintain the rate of 405,000 gallons/day. Even if the Company could transport 12 million gallons in 30 days, could it transport and dispatch 405,000 gallons each day for 124 days? The ability to transport the full 50 million gallons remains to be proven.

Apparently local propane trucking companies have five to ten more trucks readily available for use should Boston Gas need them. However, the Company has not documented this claim. The Siting Council believes that the Company needs to more clearly state how it plans to truck and dispatch the 47.5 million gallons (4,361 MDth) of propane necessary to meet design heating season requirements during the 1986-87 winter without DOMAC LNG.[68] We ask the Company to state whether it plans to acquire more trucks to transport propane and, if so, how many and from whom it will acquire them. Whether or not the

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63. 400,000 barrels is equal to 16.8 million gallons or about 1,540 MDth of propane.
64. Response to Data Request S-6; Tr., November 25, 1985, at 103-106.
65. 1984 Supplement, Appendix A, at 12; Tr., November 25, 1985, at 103-106.
66. 1984 Supplement, Appendix A, at 12.
67. 1984 Supplement, Appendix A, at 13.
68. See Section VI.A.2.b., <u>infra</u>.

TABLE 9

Boston Gas Propane Delivery Capacities

Maximum Winter Throughput	50 Million Gallons	(4,587 MDth)
Tank Capacity	16.8 Million Gallons	(1,540 MDth)
Ship Delivery Capacity	10.5 Million Gallons	(963 MDth)
* Maximum Withdrawl Rate	720,000 gal/day	(66.1 MDth/day)
** Est Maximum Trucking Rate	405,000 gal/day	(37.2 MDth/day)
Everett Propane SNG Plant Production Capacity	435,000 gal/day	(40.0 MDth/day)
Other Boston Gas Propane-Air Capacity	795,000 gal/day	(72.9 MDth/day)
Estimated Time to Truck 50 Million Gallons	At 720,000 gal/day = 70 Days At 405,000 gal/day = 124 Days	

* Assuming withdrawl to trucks.
** Assuming 10 trucks available.

Source: 1984 Supplement, Appendix A; Response to Data Request S-8; Tr., November 25, 1985, at 103-106.

Company plans to acquire additional trucks, it should estimate the rate at which trucks can transport propane over an extended period of time and the length of time necessary to transport 47.5 million gallons of propane from Newington, New Hampshire to Boston. The Company should also estimate the ability of propane-air facilities to operate over the same extended period of time and send out 4,361 MDth of propane-air. The Company should clearly state all assumptions in this analysis such as the number of trucks, the number of hours per day of truck operation, the daily trucking rate, the number of hours per day propane-air facilities are expected to operate, and the number of days as well as the hours per day that customer demand can absorb the necessary level of propane sendout. This analysis is appended as Condition 4.

For the right to terminal 50 million gallons of propane, Sea-3 charges Boston Gas a fixed rate of $2,580,000/year. If Boston Gas has propane inventories left on April 30 of any contract year, it must pay a fee of $.0025/gallon/month to store those inventories in the tank over the summer.[69] If Boston Gas needs to terminal quantities above 50 million gallons and Sea-3 has the capacity available, Boston Gas may do so for a fee of $0.10/gallon.[70]

So far Boston Gas has not attempted to make purchases directly

69. Apparently Boston Gas will leave about 5.1 million gallons in storage this summer. The charges for this service should be about $75,000.
70. Response to Data Request S-6.

on the propane market. Sea-3, through one of its affiliate companies, sells propane at the Newington LPG tank and therefore Boston Gas has been buying its propane from Sea-3. In all, Boston Gas believes it has a secure and flexible arrangement with Sea-3 such that the Company can import and terminal its own propane as well as easily purchase additional propane as necessary.[71]

C. Changes in Existing Contracts

1. Pipeline Supplies

Boston Gas' F-1 and WS-1 contracts with Algonquin for firm baseload and winter service, respectively, expire within the forecast period.[72] However, Algonquin's primary supplier, Texas Eastern, has told its customers that supplies will be available at current levels at least through 1994. Thus, Boston Gas expects that Algonquin will agree to extend the contracts thereby allowing the Company to receive full delivery of contract volumes through the end of the forecast period.[73]

The Siting Council is very interested in new developments on primary supply contracts like F-1 and WS-1. In its next filing the Company should explain any new developments on these contracts such as extension, termination, or renegotiation of terms.

2. SNG-1 Contract

Since 1973 Algonquin has supplied SNG to Boston Gas and other New England gas companies under the SNG-1 rate schedule. During times of pipeline supply curtailments in the 1970s SNG was an important winter supply. However, due to increased availability of lower cost pipeline supplies and storage services in recent years, Boston Gas and other SNG-1 customers negotiated reductions in their SNG contracts. Boston Gas SNG volumes were reduced to 96 MDth for the 1984-85 heating season and to zero for the two remaining contract years.[74]

Since that negotiated reduction in 1984, Algonquin has filed a petition at FERC to abandon altogether its SNG-1 contract effective March 31, 1986. In the petition Algonquin notes that it has negotiated settlements with all customers to carry the remaining plant depreciation charges without delivery of any SNG. Algonquin believes it would be less expensive to retire the plant immediately rather than leave the plant open for another year and charge customers the relatively high operating costs.[75]

In our last decision we acknowledged Boston Gas' efforts to reduce its gas costs, and we urged the Company to continue to renegotiate its contractual obligations for high-cost supplies.[76]

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71. 1984 Supplement, Appendix A, at 9.
72. 1985 Forecast, Table G-24.
73. 1985 Forecast, Table G-22; Response to Data Request S-7.
74. Response to Data Request S-8.
75. See Algonquin Gas Transmission Company, FERC Docket No. CP86-407.
76. 10 DOMSC 278, 310 (1984).

Boston Gas' SNG contract settlement shows clear progress in that regard. We commend Boston Gas for its efforts, and we encourage the Company to report in its next filing on the status of the SNG-1 contract abandonment.

3. DOMAC Contract

Several changes in the status of Boston Gas' LNG contract with Distrigas of Massachusetts Corporation have occurred since the Siting Council's last Boston Gas decision. Condition 3 in that decision asked Boston Gas to "use all due diligence in all future negotiations to seek remedies that will reasonably reduce its costs and risks" associated with the Company's DOMAC supplies.[77]

The Company responded by reporting a number of legal efforts to reduce its reliance on DOMAC. The Company has participated in proceedings at the Economic Regulatory Administration ("ERA") and FERC on issues surrounding DOMAC. In particular, Boston Gas negotiated a settlement with Distrigas/DOMAC in which DOMAC agreed to reduce the Company's contractual requirements in exchange for the Company's withdrawl of its protest of an amendment to the Distrigas - Sonatrach contract[78]; the Company intervened in the FERC proceedings on DOMAC's request for relief from FERC Order No. 380[79]; the Company filed protest in FERC's proceedings reviewing a DOMAC application to change its rate design[80]; finally, the Company opposed DOMAC's filing to recover unrecovered purchased gas costs resulting from the refusal by two DOMAC customers (neither of which includes Boston Gas) to take or pay for their share of 1985 summer period cargoes.[81,82]

To reduce its costs, Boston Gas chose to exercise its right under FERC Order 380 to refuse delivery of a DOMAC LNG shipment schedued to arrive on October 1, 1985. The Company found that other supply options available at the time were less expensive and that it could reduce the cost burden on its customers by using more economical supplies.[83]

To reduce its risks, Boston Gas has developed a contingency supply plan in the event of a DOMAC LNG interruption. The Company has long perceived DOMAC deliveries as unreliable and prior to 1979 adopted a policy of not relying on those deliveries. The contingency plan consists of retaining terminalling rights for sufficient propane

77. 10 DOMSC 278, 314 (1984). See Condition 3 listed in Section II, supra.
78. See Distrigas Corporation, ERA Docket No. 82-13-LNG.
79. See Distrigas of Massachusetts Corporation, FERC Docket No. RP84-109.
80. See Distrigas of Massachusetts Corporation, FERC Docket No. RP85-125.
81. See Distrigas of Massachusetts Corporation, FERC Docket No. RP85-165.
82. 1984 Supplement, Appendix A; Response to Data Request 3, May 1986.
83. Tr., November 25, 1985, at 50.

to meet design year requirements without any DOMAC LNG.[84,85]

The Siting Council is satisfied that Boston Gas has used due diligence to seek to reduce its costs and risks surrounding DOMAC LNG, and therefore the Siting Council approves the Company's compliance with Condition 3 of the previous decision. Since the future status of DOMAC supplies remains uncertain, we request that the Company continue to keep us up-to-date in future forecast filings.

VI. COMPARISON OF RECOURCES AND REQUIREMENTS

A. Annual Supplies

1. Normal Year

Boston Gas must have adequate supplies to meet four types of requirements in a normal year. First and foremost, it must meet the sendout requirements of its firm customers. It must insure that its underground storage facilities are filled to capacity prior to the start of each heating season. It must refill its LNG storage year-round as required to meet daily sendout fluctuations and to allow Distrigas LNG ships to be unloaded as they arrive. Lastly, it must account for the losses that are incurred during the transportation of pipeline gas and during the injection and withdrawl of storage gas. Tables 10 and 11 review the Company's forecast of these requirements and the anticipated supply sources for meeting the requirements during each heating and non-heating season over the forecast period.

There are a few points worth noting in these tables. The Company expects delivery of 6,000 MDth of DOMAC LNG during the heating season and no volumes during the non-heating season. The Company believes its request will be granted to reduce DOMAC volumes to these levels from the levels of 7,200 MDth during the heating season and 6,309 MDth during the non-heating season expected in the 1984 Supplement.[86] As partial replacement of the decreased DOMAC supplies, the Company expects to increase its supplies on the Tennessee side of its system. This expectation is clear in Tables 10 and 11: Tennessee heating season supplies (including firm return) are expected to grow by 34 percent over the five-year forecast; Tennessee non-heating season supplies are expected to grow by 51 percent over four years. The increased Tennessee supplies are attributed to the INGS/Boundary and AVL projects described in Sections V.A.3. and V.A.4., supra.

Boston Gas will meet most of its firm load growth during the forecast period with the increased Tennessee pipeline volumes. The remaining load growth will be met with additional Algonquin supplies. The Company expects the additional Algonquin volumes necessary during

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84. 1984 Supplement, at 13; Response to Data Request S-25; Tr., November 25, 1985, at 98-110.
85. For details on the terminalling arrangement, see Section V.B.4., supra.
86. 1984 Supplement, Table G-22; 1985 Forecast, Table G-22.

TABLE 10

Comparison of Resources and Requirements
Normal Heating Season
(MDth)

REQUIREMENTS	1985-86	1986-87	1987-88	1988-89	1989-90
Normal Firm Sendout	45,655	47,715	49,363	51,011	52,659
Fuel Reimbursement	166	225	213	201	282
Interruptible	0	0	0	0	0
Storage Refill	0	0	0	0	0
TOTAL REQUIREMENTS	45,821	47,940	49,576	51,212	52,941
RESOURCES					
TGP CD-6	12,422	12,191	14,783	15,698	15,865
Firm Return	1,532	1,488	1,403	1,313	1,307
Boundary	0	0	0	0	1,584
TGP SUBTOTAL	13,954	13,679	16,186	17,011	18,756
AGT F-1	17,775	17,593	17,166	18,341	18,277
F-2	0	3,229	3,229	3,229	3,229
F-3	0	956	956	956	956
F-4	1,401	0	0	0	0
WS-1	2,802	2,894	2,894	2,894	2,894
STB	3,080	3,016	2,798	2,655	2,662
SIS/SS-III	842	607	379	160	201
SNG-1	0	0	0	0	0
Trans-Niagara	0	0	0	0	0
AGT SUBTOTAL	25,900	28,295	27,422	28,235	28,219
LNG From Storage	1,669	1,709	1,619	1,704	1,696
DOMAC LNG	6,000	6,000	6,000	6,000	6,000
LNG Boiloff	250	250	250	250	250
DOMAC to Refill	(1,952)	(1,993)	(1,901)	(1,988)	(1,980)
Firm Propane	0	0	0	0	0
NON-PIPELINE SUBTOTAL	5,967	5,966	5,968	5,966	5,966
TOTAL RESOURCES	45,821	47,940	49,576	51,212	52,941

Source: 1985 Forecast, Table G-22.

TABLE 11

Comparison of Resources and Requirements
Normal Non-Heating Season *
(MDth)

REQUIREMENTS	1986-87	1987-88	1988-89	1989-90
Normal Firm Sendout	22,590	22,942	23,294	23,646
Fuel Reimbursement	88	57	57	57
Interruptible	5,451	4,979	7,688	10,463
Storage Refill:				
Underground	5,806	5,111	4,615	4,128
Liquefaction	350	350	350	350
TOTAL REQUIREMENTS	34,285	33,439	36,004	38,644
RESOURCES				
TGP CD-6	12,032	12,263	14,401	18,216
Firm Return	37	0	0	0
Boundary	0	0	0	0
TGP SUBTOTAL	12,069	12,263	14,401	18,216
AGT F-1	16,531	16,713	17,140	15,965
F-2	0	674	674	674
F-3	0	199	199	199
F-4	1,987	0	0	0
WS-1	92	0	0	0
STB	16	0	0	0
SIS/SS-III	0	0	0	0
I-1	3,240	3,240	3,240	3,240
SNG-1	0	0	0	0
Trans-Niagara	0	0	0	0
AGT SUBTOTAL	21,866	20,826	21,253	20,078
LNG From Storage	0	0	0	0
DOMAC LNG	0	0	0	0
LNG Boiloff	350	350	350	350
DOMAC to Refill	0	0	0	0
Firm Propane	0	0	0	0
NON-PIPELINE SUBTOTAL	350	350	350	350
TOTAL RESOURCES	34,285	33,439	36,004	38,644

* 1985-86 non-heating season forecast not required.

Source: 1985 Forecast, Table G-22.

the heating season to be about nine percent over five years while the Algonquin non-heating season supplies remain relatively constant throughout the forecast period. With the addition of all this pipeline gas, Boston Gas does not expect to need any additional peak shaving supplies during a normal year.

Based on the record as shown in Tables 10 and 11, the Siting Council concludes that the Company's supply plan is sufficient to meet normal sendout requirements subject to the Company's sendout and supply assumptions stated herein.

2. Design Year

During a design year Boston Gas must have sufficient supplies to meet the additional firm sendout requirements above normal year. The Company analyzed two design year scenarios in its 1985 Forecast filing: Design year with full delivery from DOMAC of 6,000 MDth of LNG, and design year under the contingency of no DOMAC LNG delivery.

a. Adequacy of Design Year Supplies

Table 12 summarizes Boston Gas' supply plan to meet design heating season requirements assuming full DOMAC LNG delivery. These design requirements are expected to be about 11 percent above normal requirements during the heating season throughout the forecast period. Table 13 identifies the additional resources the Company expects to use in a design heating season to meet the requirements above normal.

A review of Table 13 shows that the Company plans to meet its additional requirements with Tennessee and Algonquin pipeline gas as well as with extra peak shaving resources. Although SNG-1 is no longer available and DOMAC LNG is estimated to decrease from 7,200 MDth per heating season to 6,000 MDth per heating season, the additional firm contracts and potential new supplies in the Company's supply plan more than adequately replace the SNG and LNG removed from the plan.[87] From Table 13 it is clear that the Company plans to reduce its dependence on peak shaving supplies over the forecast period by shifting to reliance on additional pipeline resources, particularly Tennessee resources. The Siting Council approves of such a shift since delivery of pipeline supplies is generally less expensive than peak shaving supplies.

If design requirements are under-forecast, the Company has firm reserve supplies available. Some firm pipeline volumes are still available under the F-1 and CD-6 contracts, and small quantities of storage return under the SS-III contract are available during the last two forecast years. However, the most firm reserve supplies are from non-pipeline sources. Almost all of the Company's 4,587 MDth of firm propane is in reserve.[88] The Company's trucking ability may hinder

87. Additional firm contracts include AGT F-2, F-3, F-4, and SS-III and TGP storage return; potential new supplies include TGP AVL and INGS/Boundary. See Section V.A., V.B., and V.C., supra.
88. We say "almost all" because Boston Gas' design heating season supply plan requires the use of a small portion of that propane.

TABLE 12

Comparison of Resources and Requirements
Design Heating Season -- With DOMAC
(MDth)

REQUIREMENTS	1985-86	1986-87	1987-88	1988-89	1989-90
Design Firm Sendout	50,655	52,924	54,742	56,559	58,376
Fuel Reimbursement	178	252	246	239	319
Interruptible	0	0	0	0	0
Storage Refill	0	0	0	0	0
TOTAL REQUIREMENTS	50,833	53,176	54,988	56,798	58,695
RESOURCES					
TGP CD-6	13,564	13,509	16,635	18,565	18,521
Firm Return	1,678	1,630	1,574	1,533	1,531
Boundary	0	0	0	0	1,584
TGP SUBTOTAL	15,242	15,139	18,209	20,098	21,636
AGT F-1	19,089	18,969	18,323	18,905	18,863
F-2	0	3,229	3,229	3,229	3,229
F-3	0	956	956	956	956
F-4	1,401	0	0	0	0
WS-1	2,894	2,894	2,894	2,894	2,894
STB	3,500	3,500	3,380	3,216	3,212
SIS/SS-III	842	1,064	1,064	932	974
SNG-1	0	0	0	0	0
Trans-Niagara	0	0	0	0	0
AGT SUBTOTAL	27,726	30,612	29,846	30,132	30,128
LNG From Storage	4,320	4,071	3,868	3,764	4,042
DOMAC LNG	5,664	5,805	5,989	6,000	6,000
LNG Boiloff	250	250	250	250	250
DOMAC to Refill	(2,508)	(2,865)	(3,353)	(3,640)	(3,575)
Firm Propane	139	164	179	194	214
NON-PIPELINE SUBTOTAL	7,865	7,425	6,933	6,568	6,931
TOTAL RESOURCES	50,833	53,176	54,988	56,798	58,695

Source: 1985 Forecast, Table G-22.

TABLE 13

Comparison of Resources and Requirements
Design Heating Season vs. Normal Heating Season *
With DOMAC
(MDth)

REQUIREMENTS	1985-86	1986-87	1987-88	1988-89	1989-90
Firm Sendout	5,000	5,209	5,379	5,548	5,717
Fuel Reimbursement	12	27	33	38	37
Interruptible	0	0	0	0	0
Storage Refill	0	0	0	0	0
ADDITIONAL REQUIREMENTS	5,012	5,236	5,412	5,586	5,754
RESOURCES					
TGP CD-6	1,142	1,318	1,852	2,867	2,656
Firm Return	146	142	171	220	224
Boundary	0	0	0	0	0
ADDITIONAL TGP	1,288	1,460	2,023	3,087	2,880
AGT F-1	1,314	1,376	1,157	564	586
F-2	0	0	0	0	0
F-3	0	0	0	0	0
F-4	0	0	0	0	0
WS-1	92	0	0	0	0
STB	420	484	582	561	550
SIS/SS-III	0	457	685	772	773
SNG-1	0	0	0	0	0
Trans-Niagara	0	0	0	0	0
ADDITIONAL AGT	1,826	2,317	2,424	1,897	1,909
LNG From Storage	2,651	2,362	2,249	2,060	2,346
DOMAC LNG	-336	-195	-11	0	0
LNG Boiloff	0	0	0	0	0
DOMAC to Refill	-556	-872	-1,452	-1,652	-1,595
Firm Propane	139	164	179	194	214
ADDITIONAL NON-PIPELINE	1,898	1,459	965	602	965
ADDITIONAL RESOURCES	5,012	5,236	5,412	5,586	5,754

* This table represents the increased requirements and resources in a design heating season over a normal heating season.

Source: 1985 Forecast, Table G-22.

its use of the full 4,587 MDth[89] but, since the propane is a reserve supply, having most of it available still represents a good source to meet any requirements above design. In addition, the Company has over 2,500 MDth of its own LNG which it can dispatch if necessary.[90] The non-pipeline supplies also serve as resources available should delays arise in either the TGP AVL increase or the INGS/Boundary project.

We noted previously[91] that the Company's load growth estimates are ambitious and perhaps even over-forecast. It does not appear to be coincidental that very little firm supply reserve is available from pipelines during a design heating season -- the Company's sendout forecasting methodology uses available pipeline supplies as the limiting factor on load growth even though it remains to be proven whether or not that assumption is still valid.[92] However, if indeed requirements are over-forecast, the Company would have even more design (and normal) supply reserve resulting in increased cost per unit of supply but also in increased reliability that firm requirements will be met.

The Siting Council concludes that when DOMAC supplies are available Boston Gas has sufficient resources to meet its design sendout requirements.

b. DOMAC Contingency

As part of its 1985 Forecast the Company presented its plans for the most likely supplies it would use to meet firm requirements in the event of no DOMAC LNG deliveries. The Siting Council appreciates this type of contingency analysis and commends the Company for taking the initiative to prepare and submit the plans. Table 14 summarizes the Company's contingency plan for a design heating season; Table 15 compares the supply sources when DOMAC LNG is available (Table 12) with the sources when DOMAC LNG is not available (Table 14).

Analysis of Table 15 comparing the supply scenarios with and without DOMAC LNG yields a number of subtleties. As expected, firm requirements remain the same regardless of whether or not DOMAC supplies are available. The other two requirements, fuel reimbursement and storage refill, slightly increase in the case of no DOMAC LNG due to the restructuring of the supply plan to increase pipeline gas transportation, increase underground storage withdrawl, and begin refilling LNG storage.

It is clear from the TGP and AGT resource changes noted in Table 15 that the additional LNG storage refill requirements would be met with CD-6 and F-1 supplies. However, in the two final forecast years the Company indicates increased STB storage withdrawl to the maximum allowable under contract which appears to help refill LNG.[93] The Siting Council needs justification for using one storage

89. See Section V.B.4., <u>infra</u>.
90. 1984 Supplement, at 17-19; 1985 Forecast, Table G-22.
91. See Section IV.B.1.a., <u>supra</u>.
92. See Section IV., <u>supra</u>.
93. The CD-6, F-1, and STB increases also account for the additional fuel reimbursement charges and payment.

TABLE 14

Comparison of Resources and Requirements
Design Heating Season -- No DOMAC
(MDth)

REQUIREMENTS	1985-86	1986-87	1987-88	1988-89	1989-90
Design Firm Sendout	50,655	52,924	54,742	56,559	58,376
Fuel Reimbursement	178	298	314	314	397
Interruptible	0	0	0	0	0
Storage Refill: Liquif.	0	454	641	681	734
TOTAL REQUIREMENTS	50,833	53,676	55,697	57,554	59,507
RESOURCES					
TGP CD-6	13,468	13,794	16,481	18,909	18,923
Firm Return	1,678	1,629	1,574	1,532	1,530
Boundary	0	0	0	0	1,584
TGP SUBTOTAL	15,146	15,423	18,055	20,441	22,037
AGT F-1	19,186	19,186	19,186	19,186	19,186
F-2	0	3,229	3,229	3,229	3,229
F-3	0	956	956	956	956
F-4	1,401	0	0	0	0
WS-1	2,894	2,894	2,894	2,894	2,894
STB	3,500	3,500	3,380	3,216	3,212
SIS/SS-III	842	1,064	1,064	1,064	1,064
SNG-1	0	0	0	0	0
Trans-Niagara	0	0	0	0	0
AGT SUBTOTAL	27,823	30,829	30,709	30,545	30,541
LNG From Storage	3,543	2,813	2,853	2,906	2,912
DOMAC LNG	0	0	0	0	0
LNG Boiloff	250	250	250	250	250
DOMAC to Refill	0	0	0	0	0
Firm Propane	4,071	4,361	3,830	3,412	3,767
NON-PIPELINE SUBTOTAL	7,864	7,424	6,933	6,568	6,929
TOTAL RESOURCES	50,833	53,676	55,697	57,554	59,507

Source: 1985 Forecast, Table G-22.

TABLE 15

Comparison of Resources and Requirements
Design Heating Season: With DOMAC vs. Without DOMAC *
(MDth)

REQUIREMENTS	1985-86	1986-87	1987-88	1988-89	1989-90
Design Firm Sendout	0	0	0	0	0
Fuel Reimbursement	0	46	68	75	78
Interruptible	0	0	0	0	0
Storage Refill	0	454	641	681	734
ADDITIONAL REQUIREMENTS	0	500	709	756	812
RESOURCES					
TGP CD-6	-96	285	-154	344	402
Firm Return	0	-1	0	-1	-1
Boundary	0	0	0	0	0
ADDITIONAL TGP	-96	284	-154	343	401
AGT F-1	97	217	863	281	323
F-2	0	0	0	0	0
F-3	0	0	0	0	0
F-4	0	0	0	0	0
WS-1	0	0	0	0	0
STB	0	0	0	0	0
SIS/SS-III	0	0	0	132	90
SNG-1	0	0	0	0	0
Trans-Niagara	0	0	0	0	0
ADDITIONAL AGT	97	217	863	413	413
LNG From Storage	-777	-1,258	-1,015	-858	-1,130
DOMAC LNG	-5,664	-5,805	-5,989	-6,000	-6,000
LNG Boiloff	0	0	0	0	0
DOMAC to Refill	2,508	2,865	3,353	3,640	3,575
Firm Propane	3,932	4,197	3,651	3,218	3,553
ADDITIONAL NON-PIPELINE	-1	-1	0	0	-2
ADDITIONAL RESOURCES	0	500	709	756	812

* This table represents changes to the supply plan that includes DOMAC LNG. That is, positive numbers indicate increases in requirements and resources in the event that DOMAC supplies are not available.

Source: 1985 Forecast, Table G-22.

gas to refill another. While dispatching considerations may necessitate such an arrangement, the Company has not made that indication. We request that the Company explain in its next filing its reasoning for increasing both its storage refill reqirements and its storage withdrawl in the event of a heating season with no DOMAC deliveries.

The major change in the Company's supply plan given a DOMAC supply contingency is the shift from DOMAC LNG to propane supplies and its own LNG storage. During the 1986-87 heating season Boston Gas will need 4,361 MDth[94] of its 4,587 MDth terminalling contract with Dorchester Sea-3 Products in Newington, New Hampshire. The Siting Council has stated its reservations about the Company's ability to truck such a vast quantity of propane to Boston.[95] We expect the Company to faithfully comply in its next filing with Condition 4 of this decision.

The Company also plans to use more of its own LNG storage to replace DOMAC supplies. Table 15 seems to indicate a decrease in use of the Company's own LNG storage if DOMAC LNG is not available. However, this is a decrease in the amount of LNG dispatched from the Company's LNG tank. During the course of a heating season with DOMAC LNG available, the Company trucks LNG from DOMAC's LNG tank to its own tank and dispatches the LNG from there.[96] Thus, while the Company dispatches less LNG in total from its own tank, it still dispatches more of its own LNG.

Table 14 indicates that Boston Gas will use about 3,543 MDth of stored LNG in the first forecast heating season and about 2,800 MDth to 2,900 MDth in each heating season thereafter. The Company's full LNG storage volumes are listed in Table 16 below.

TABLE 16

Boston Gas LNG Storage Volumes
(MDth)

Tank Owner/Lessee	Tank Location	Capacity
Boston Gas	Dorchester	2,140
Mass. LNG	Salem	1,000
Mass. LNG	Lynn	1,000
DOMAC *	Everett	643
Algonquin LNG	Providence, RI	400
		5,183

* Although DOMAC supplies remain uncertain, firm storage capacity remains available in DOMAC's Everett LNG tank.

Source: 1984 Supplement.

94. 4,361 MDth is the equivalent of about 47.5 million gallons of propane. The Company may terminal up to 50 million gallons of propane at Newington, New Hampshire. See Section V.B.4., supra.
95. See Section V.B.4., supra.
96. This amount of LNG is listed in Tables 10 through 15 under the category "DOMAC to Refill".

The difference of 1,640 MDth to 2,370 MDth between available LNG storage capacity and expected LNG sendout seems to be the supply reserve available either to meet any requirements above design forecast or to serve as back-up supplies for any other resource such as propane. However, this assumption does not stand without qualification. Boston Gas' ability to replenish its LNG storage by liquifying pipeline gas is limited by daily sendout fluctuations during the non-heating season. If Boston Gas draws its LNG levels down too low, it may not be able to fully replenish them prior to the next heating season. Thus, when the Company enters a heating season with its LNG inventories full, the 1,640 MDth to 2,370 MDth LNG surplus serves as reserve for the first heating season. But if Boston Gas dispatches more LNG during that first heating season than it can replenish, the reserve for the next heating season is reduced.

Boston Gas has not indicated what the threshold level of LNG is that it can liquify each summer at each tank. The Siting Council realizes the Company may not know itself its exact liquifying capability due to the influence of sendout on liquifaction rate. We note that the Company is contemplating installing compressor capacity at its Columbia Point (Dorchester) LNG tank to insure that it can liquify at full capacity regardless of sendout fluctuations.[97]

Since the Company's LNG capability is important in the event of a DOMAC supply disruption, the Siting Council is concerned about LNG limitations. Therefore, we order the Company to fully report in its next filing the operating limitations on the LNG tanks that it owns or retains for storage capacity including those in Dorchester, Salem, Lynn, Everett, and Providence. Such report shall include tank capacity, form of LNG replenishment (liquifaction, trucked LNG, etc.), rate at which LNG can be replenished both in the heating and non-heating seasons (or by some other appropriate disaggregation such as by month), and the factor limiting the rate of replenishment. If Boston Gas does not have the ability to fill its entire LNG storage capacity at any tank during any non-heating season, it shall either state how it plans to acquire such an ability or justify why such an ability is not necessary. This order is listed as Condition 5.

The Siting Council finds it difficult to follow the Company's plans for dispatching LNG when all LNG storage is aggregated in Table G-22 (and Table G-23) under the category "LNG From Storage". Thus, the Company is further ordered to disaggregate by LNG tank location[98] its category "LNG From Storage" in Tables G-22 and G-23 in <u>all future filings</u>. This order is listed as Condition 6.

We believe it would be imprudent to make a determination at this time on the adequacy of the Company's contingency plan to meet design requirements in the event of a DOMAC LNG disruption. Three

97. 1984 Supplement, Section 3.
98. The Siting Council's intent is that each tank should be listed separately except for cases where there is more than one tank at a given site. For instance, the Company's two tanks at Columbia Point may be listed as one tank location.

pieces of information we are requesting in the next filing, propane trucking ability, LNG operating limitations, and disaggregated LNG inventory reporting, should allow a better understanding of the plan adequacy. Therefore, we order Boston Gas to submit in its next filing an updated version of the same contingency plan including Table G-22D -- No Distrigas for the heating season and non-heating season as well as the back-up data contained in Table G-22B -- No Distrigas. This order is listed as Condition 7.

B. Daily Supplies: Design Day

As part of its supply planning process the Company plans for a design day sendout during the winter.[99] Table 17 summarizes the Company's plan for supplying a design day each year over the forecast as well as the actual supplies the Company used to meet its 1984-85 peak day.

We noted in Section IV.B.2., supra, that Boston Gas is forecasting design day growth over the forecast period of 153 MDth, or 23.5 percent. Table 17 shows that Boston Gas plans to meet this extraordinary level of growth with a combination of increased pipeline supplies (particularly from Tennessee) and supply reserve reduction. The increase in pipeline supplies will be from the Tennessee AVL and INGS/Boundary projects and from the Algonquin F-2 and F-3 projects. Of those projects only the F-2 and F-3 supplies are presently under signed contract. Boston Gas expects non-pipeline supplies to remain at their present capacity throughout the forecast period.

Boston Gas includes DOMAC LNG in its design day supply plan available at a rate of 45.0 MDth/day. If this supply were not available Boston Gas would still have enough design day supply throughout the forecast period, but its reserve margin would be substantially reduced. The Siting Council believes the Company should analyze the impact of the possibility of a DOMAC supply interruption on a design day. As Condition 8 of this decision we require the Company to submit a contingency plan in the form of Table G-23 for the event that DOMAC supplies are not available on a design day.

Planning an appropriate level of design day reserve is important to the Siting Council. This level must balance (1) the uncertainty in the sendout forecast with the cost of the incremental resource to compensate for that uncertainty, and (2) the reliability of each resource with its cost, all subject to supply contract and distribution system constraints. The Siting Council requests that the Company carefully consider the appropriate level of design day reserve (and design year reserve) in the survey and forecast methodology evaluation ordered in Condition 3 of this decision.

Given the uncertainties in design day load growth, new TGP supplies, and DOMAC LNG, the Siting Council finds it difficult to make a clear determination on the adequacy of the company's design day supply plan. The Company does not appear to have a problem meeting

99. The Company's peak day forecasting methodology is described in Section IV., supra.

TABLE 17

Comparison of Resources and Requirements
Design Day Sendout (With DOMAC)
(MDth)

REQUIREMENTS	* 1984-85	1985-86	1986-87	1987-88	1988-89	1989-90
Firm Sendout	514.4	682.7	714.5	746.4	778.2	803.8
Interruptible	3.9	0.0	0.0	0.0	0.0	0.0
Storage Refill	0.0	0.0	0.0	0.0	0.0	0.0
Other	6.5	0.0	0.0	0.0	0.0	0.0
TOTAL REQUIREMENTS	524.8	682.7	714.5	746.4	778.2	803.8
RESOURCES						
TGP CD-6	96.7	96.2	96.2	114.8	133.5	133.5
Firm Return	0.0	12.7	12.7	12.7	12.7	12.7
Best Efforts	6.0	0.0	0.0	0.0	0.0	0.0
Boundary	0.0	0.0	0.0	0.0	0.0	10.0
TGP SUBTOTAL	102.7	108.9	108.9	127.5	146.2	156.2
AGT F-1	127.1	127.1	127.1	127.1	127.1	127.1
F-2	0.0	0.0	20.9	20.9	20.9	20.9
F-3	0.0	0.0	6.2	6.2	6.2	6.2
F-4	0.0	9.1	0.0	0.0	0.0	0.0
WS-1	38.4	48.2	48.2	48.2	48.2	48.2
STB	30.4	29.7	29.7	29.7	29.7	29.7
SIS/SS-III	8.2	0.0	0.0	0.0	0.0	0.0
SNG-1	3.1	0.0	0.0	0.0	0.0	0.0
Trans-Niagara	0.0	0.0	0.0	0.0	0.0	0.0
AGT SUBTOTAL	207.2	214.1	232.1	232.1	232.1	232.1
LNG From Storage	138.6	308.7	308.7	308.7	308.7	308.7
DOMAC LNG	76.4	45.0	45.0	45.0	45.0	45.0
DOMAC to Refill	0.0	0.0	0.0	0.0	0.0	0.0
Firm Propane	0.0	112.9	112.9	112.9	112.9	112.9
NON-PIPELINE SUBTOTAL	215.0	466.6	466.6	466.6	466.6	466.6
TOTAL RESOURCES	524.8	789.6	807.6	826.2	844.9	854.9
RESERVE MARGIN	---	107.0	93.1	79.8	66.7	51.1
RESERVE RATIO	---	15.7%	13.0%	10.7%	8.6%	6.4%

* 1984-85 data are for January 21, 1985, the actual peak day during that heating season. The average temperature that day was 9'F; all other peak days are based on the Company's design day temperature, -8'F.

Source: 1985 Forecast, Table G-23.

peak day for the first two forecast years, and therefore we will approve its design day supply plan for this interim period. We hope the Company realizes that, over time, the magnitude of uncertainties noted above should be quantified and hopefully reduced.

VII. IMPACT OF ORDER IN DOCKET NO. 85-64

The Siting Council's Order in Docket No. 85-64, along with Administrative Bulletin No. 86-1 implementing that Order, changes some of the future filing requirements to be met by Massachusetts gas companies. For the Company's convenience, the changes affecting its preparation of its next forecast filing are briefly outlined below.

A. Forecast Accuracy

The Siting Council is instituting a requirement that each gas company report on the accuracy of its past forecasts, vis-a-vis actual normalized sendout for the same years. A new table for reporting the accuracy, Table FA, was issued in Administrative Bulletin No. 86-1. We note that the instructions for Table FA request remarks on forecast methodology changes that may influence accuracy. We also encourage the Company to briefly analyze and comment on the accuracy results in Section 1 of its filing.

B. Weather Normalization and Design Weather Selection

The Order in Docket No. 85-64 requires gas companies to describe in detail and justify their approach to normalization of sendout for weather and selection of design weather conditions. The Siting Council is aware that the Company testified at length before the Massachusetts Department of Public Utilities ("DPU") in DPU Docket Nos. 555 and 555-C[100] on the Company's weather analysis. The Siting Council is willing to allow Boston Gas to incorprate any of that testimony by reference as long as the Company references specific documents, those documents are readily available either from the DPU or the Company, and the information contained therein adequately explains the Company's normalization process and design weather criteria selection. We welcome any supplemental analysis.

C. New Split Year

On the recommendation of many gas companies including Boston Gas, the Siting Council has determined that its split year should

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100. See "Investigation by the Department on Its Own Motion as to the Reasons For, or Causes of, the Shortage of Natural Gas Throughout the Commonwealth Supplied by All Gas Companies Under the Jurisdiction of the Department During the 1980-81 Season", <u>Department of Public Utilities</u>, DPU Docket No. 555; and "Adjudicatory Investigation by the Department on Its Own Motion in Accordance With the Legislative Report Issued in D.P.U. 555 as to the Reasons for, and Causes of, the Shortage of Natural Gas During the 1980-81 Season on the System of Boston Gas Company", <u>Department of Public Utilities</u>, DPU Docket No. 555-C.

begin in November as the heating season begins rather than in April. This change will require Boston Gas to recalculate its sendout for each historical base year in its forecast on a one-time basis. The Siting Council recognizes that this will cause some inconvenience in the preparation of the Company's 1986 forecast, but expects that over the long run the new split year will improve forecast accuracy and reliability.

D. Analysis of Cold Snap Preparedness

The Order in Docket No. 85-64 requires that in their next filings all large- and medium-size companies (Boston Gas is a large-size company) submit an analysis of their cold-snap preparedness to demonstrate that they will be able to meet their firm sendout obligations throughout a protracted period of design or near-design weather. This analysis should discuss the Company's cold snap criteria, supply mix, inventory turnover practices, lead time for attaining supplemental supplies, and historical experience of equipment malfunctions, as well as the company's experience in actual historical cold periods. Alternatively, if the Company can provide an adequate explanation of why such analysis is not appropriate to the nature of its sendout and supply plan, we will consider excusing it from preparing a cold snap analysis in the future.

The Company provided some explanation of its cold snap planning process to the Siting Council in Docket No. 85-64. The Company may incorporate that record by reference. Also, the Siting Council again acknowledges the Company's testimony on cold snap preparedness in DPU Docket Nos. 555 and 555-C and is willing to allow any of that record to be incorporated by reference as long as specific documents are cited and those documents are readily available.

E. Cost Studies

In Docket No. 85-64 the Siting Council found it appropriate to begin to focus on that portion of the Siting Council's mandate that requires it to provide for an energy supply for the Commonwealth "at the lowest possible cost."[101] While the Siting Council recognizes tradeoffs between cost and reliability, the Siting Council seeks to examine the relative cost of the various supply configurations a company could use to meet its needs since supplies of similar reliability may have different costs.

In this context, the Siting Council finds that in every forecast filing where companies propose addition of a long-term firm gas supply contract within the forecast period, the companies are to perform an internal study comparing the costs of a reasonable range of practical supply alternatives. This requirement is intended to apply when the following types of contractual arrangements are proposed:

(1) changes in, amendments to, or new firm pipeline supply contracts;

101. M.G.L. c. 164, sec. 69H.

(2) changes in, amendments to, or new firm gas storage contracts or firm storage-gas transportation contracts;

(3) firm supplies of gas from a producer under a contract covering a two-year period or longer, along with related transportation arrangements; and

(4) any arrangements for supplemental fuels for which the supply is intended for use for a period longer than a single heating season, except for arrangements in which a company can adjust the volumes for the following heating season.

The Siting Council expects companies to prepare such analyses as part of their routine planning efforts when considering new major supply options. However, the Siting Council does not prescribe a particular methodology that companies must use in these cost studies. If Boston Gas is already conducting such studies, the Siting Council does not require the Company to conduct additional ones specifically for this requirement. Finally, the Siting Council does not require the submission of such cost studies as part of each forecast or forecast-supplement filing; however, Boston Gas may be required to make individual studies available to the Siting Council at its request in cases where the Siting Council or its Staff believes the results of such studies are needed to develop a complete review of the Company's supply plan.

VIII. DECISION AND ORDER

The Siting Council hereby APPROVES, subject to the CONDITIONS set forth below, the Third and Fourth Supplements to the Second Long-Range Forecast of Gas Needs and Requirements of the Boston Gas Company and Massachusetts LNG, Inc. In its next forecast, to be filed with the Siting Council on September 2, 1986, the Siting Council hereby ORDERS:

1. That the Company compare the 1985-86 split-year normal firm load growth forecasted as 2,500 MDth in the 1985 Forecast to the actual growth experienced, and that the Company compare the 1985-86 design day growth forecast as 31.9 MDth in the 1985 Forecast to the actual normalized peak day experienced. The Company should fully explain (number and type of customers, timing, normalization process, consumption rates, etc.) how the actual load growth was determined.

2. That the Company account for reduced consumption by existing customers as shown by its meter-reading study, data base reports, and other data analyses or studies. The Company should state explicitly its source(s) of data for determining the reductions in consumption per customer and its judgments in interpreting the data. Compliance with this condition may be satisfied by carefully documenting current studies, updating their status, and providing an estimate of when the results will be ready for application in a forecast.

3. That the Company evaluate the appropriateness and reliability of its present forecast methodology. All major underlying assumptions, parameters, and judgments should be evaluated on the basis of appropriateness, foundation in theory, historical reliability, and risks imposed on supply planning decisions. Such evaluation should include, but not be limited to, supply constraints, weather analysis, model selection (both annual and design day), end-use characteristics, load growth, and demographic/economic assumptions.

   The Company should also 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. The results of the survey should be used as a reference for evaluating the Company's own assumptions, data, and methodology. Upon completion of the evaluation, a report should 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. The report should include the survey results.

   The Company should meet with Staff within 30 days to discuss compliance with this condition. Boston Gas shall file its final report as part of its September 1, 1987 forecast. The Company's September 1, 1986 forecast should include a status report on compliance with this condition.

4. That the Company state whether it plans to acquire more trucks for transporting propane from the Sea-3 LPG tank in Newington, New Hampshire to Boston, and, if so, how many and from whom it will acquire them. Whether or not the Company plans to acquire additional trucks, it should estimate the rate at which trucks can transport propane over an extended period of time and the length of time necessary to transport 47.5 million gallons of propane from Newington to Boston. The Company should also estimate the ability of propane-air facilities to operate over the same period of time sending out 4,361 MDth (47.5 million gallons) of propane-air. The Company should clearly state all assumptions in this analysis such as the number of trucks, the number of hours per day of truck operation, the daily trucking rate, the number of hours per day propane-air facilities are expected to operate, and the number of days as well as the hours per day that customer demand can absorb the necessary level of propane sendout.

5. That the Company report the operating limitations on the LNG tanks that it owns or retains for storage capacity including those in Dorchester, Salem, Lynn, Everett, and Providence. Such report shall include tank capacity, form of LNG replenishment (liquifaction, trucked LNG, etc.), rate at which

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LNG can be replenished both in the heating and non-heating seasons (or by some other appropriate disaggregation such as by month), and the factor limiting the rate of replenishment. If Boston Gas does not have the ability to fill its entire LNG storage capacity at any tank during any non-heating season, it shall either state how it plans to acquire such an ability or justify why such an ability is not necessary.

6. That the Company disaggregate by LNG tank location its category "LNG From Storage" in Tables G-22 and G-23 in all future filings.

7. That the Company submit an updated version, including back-up inventory data, of its contingency plan for meeting design year requirements in the event of a DOMAC LNG supply disruption.

8. That the Company submit a contingency plan in the form of Table G-23 for the event that DOMAC supplies are not available on a design day.

9. That the Company faithfully comply with the Siting Council's Order in Docket No. 85-64 and that Order's implementation in Administrative Bulletin 86-1.

10. That the Company report on the status of DOMAC negotiations, including any volumes requested and the timing of those volumes, by July 15, 1986.

11. That the Company meet with the Siting Council Staff within 30 days of this Decision for clarification and/or assistance in defining the scope and effort required to fulfill the above conditions.

Susan F. Tierney

Susan F. Tierney
Hearing Officer

June 19, 1986

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council by the members and designees present and voting: Sarah Wald (for Paula W. Gold, Secretary of Consumer Affairs); Joellen D'Esti (for Joseph D. Alviani, Secretary of Economic and Manpower Affairs); Stephen Roop (for James S. Hoyte, Secretary of Environmental Affairs); Patricia L. Deese (Public Engineering Member); Madeline Varitimos (Public Environmental Member). Absent: Sharon M. Pollard (Secretary of

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Energy Resources); Dennis J. LaCroix (Public Gas Member); Joseph W. Joyce (Public Labor Member). Ineligible to vote: Elliot J. Roseman (Public Oil Member); Stephen Umans (Public Electricity Member).

Sharon M. Pollard

Sharon M. Pollard
Chairperson

June 30, 1986
Date

COMMONWEALTH OF MASSACHUSETTS

Energy Facilities Siting Council

In the Matter of the Petition of Berkshire Gas Company for Approval of the Fourth Supplement to the Second Long-Range Forecast of Natural Gas Requirements and Resources	)	EFSC 86-29

FINAL DECISION

Robert D. Shapiro
Hearing Officer
July 28, 1987

On the Decision:

Steven E. Oltmanns
Sheri L. Bittenbender

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The Energy Facilities Siting Council hereby REJECTS the sendout forecast and supply plan filed by the Berkshire Gas Company for the five years from 1986-87 through 1990-91.

I. INTRODUCTION

A. Background

The Berkshire Gas Company ("Berkshire" or "Company") distributes and sells natural gas in nineteen communities in Berkshire, Franklin, and Hampshire Counties. The Company has 27,358 firm customers composed of: 16,025 residential customers with gas heating; 8,426 residential customers without gas heating; 2,824 commercial customers; and 83 industrial customers (Exh. HO-1, Tables G-1, G-2, G-3A and G-3B).

The Company receives all pipeline supplies from the Tennessee Gas Pipeline Company ("Tennessee") through stations located in Pittsfield, North Adams, Stockbridge, and Northampton. Berkshire has auxiliary propane plants in Pittsfield, North Adams, Stockbridge, Greenfield, and Hatfield. Supplemental gas supplies are also available during the heating season from Bay State Gas Company ("Bay State").

Berkshire's forecast of sendout by customer class for the heating and non-heating seasons[1] is summarized in Table 1 (Exh. HO-1, Tables G-1 through G-5). Berkshire projects an increase of total normalized firm sendout from 4,758 MMcf in 1986-87 to 5,503 MMcf in 1990-91, representing an average annual growth rate of 3.7 percent. This marks an increase over the Company's previously projected growth rate of 0.9 percent annually from 1985-86 through 1989-90. Berkshire Gas Company, 14 DOMSC 107, 112 (1986).

1/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. In accordance with the directions of the Energy Facilities Siting Council ("Siting Council" or "EFSC"), Berkshire's forecast year, or "split year," begins on November 1 at the start of the heating season (Exh. HO-S-18). Berkshire Gas Company, 14 DOMSC 107, 139, 141 (1986).

B. History of the Proceedings

On November 3, 1986, the Company filed its sendout forecast and supply plan (Exh. HO-1). On November 21, 1986, the Hearing Officer issued a Notice of Adjudication and directed the Company to publish and post the Notice in accordance with EFSC Rule 15.2. After learning that the Company had not published said Notice, the Hearing Officer issued a revised Notice of Adjudication on April 9, 1987. The Company published the revised Notice in accordance with the directions of the Hearing Officer.

On May 12, 1987, the Siting Council staff conducted an evidentiary hearing. The Company presented one witness, Daniel L. Bianchi, Manager of Gas Supply and Rates, who testified regarding the Company's sendout forecast and supply plan. The Hearing Officer entered 63 exhibits in the record, largely composed of Berkshire's responses to information and record requests.

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. EFSC Rules 62.9(2)(a),(b),(c). The Siting Council's rules require that the forecast use accurate and complete historical data and reasonable statistical projection methods. 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. Boston Gas Company, EFSC 84-25, 16 DOMSC __, 19-20 (1986).

In its review of a forecast, the Siting Council determines whether 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 forecasting methodology; (b) appropriate, that is, technically suitable for 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. Bay State Gas Company, 14 DOMSC 143, 150 (1986); Boston Gas Company, EFSC 84-25, 16 DOMSC __, 8 (1986).

B. Previous Sendout Forecast Conditions

In its previous decision, the Siting Council approved Berkshire's sendout forecast subject to one condition (hereinafter "Condition One"):

> That the Company should continue to improve the documentation of its sendout forecast methodology for normal year, design year, and peak day by including formulae used in calculating customer use factors, customer number projections, the January heating use factors, and expanded descriptions of the forecast Tables in a narrative form. Berkshire Gas Company, 14 DOMSC 107, 141 (1986).

In addition, as Condition Four of its previous decision, the Siting Council ordered Berkshire to comply with its Order in Evaluation of Standards and Procedures for Reviewing Sendout Forecasts and Supply Plans of Natural Gas Utilities, EFSC 85-64, 14 DOMSC 95 (1986)[2] and that Order's implementation in Administrative Bulletin 86-1. Berkshire Gas Company, 14 DOMSC 107, 141 (1986).

Berkshire's compliance with these conditions is discussed in Sections II.C. through II.F., infra.

2/In its Order in EFSC 85-64, the Siting Council established procedures which render its review of the 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, minimal-environmental impact supply planning.

C. Normal Year

The Company forecasts normal year sendout on the basis of historic usage levels, the expected number of customers and degree days, and the expected effect of conservation. The Company defines a "normal year" as the average number of degree days in the heating and non-heating seasons over the most recent twenty-year historical period (Exh. HO-1, p. 3). In this case, the Company used the twenty-year period from April 1, 1966 to March 31, 1986. The average number of degree days in the heating and non-heating seasons in Berkshire's sendout forecast are 5,632 and 1,867, respectively (Exh. HO-1, Table DD). This represents an increase in normal year degree days since the Company's previous filing, which calculated 5,613 and 1,849 degree days for those respective seasons. Berkshire Gas Company, 14 DOMSC 107, 116 (1986).

Berkshire's normalized total firm sendout increased from 4,335 MMcf in 1984-85 to 4,454 MMcf in 1985-86 (Exh. HO-1, Table G-5). This 2.7 percent increase follows upon a five-year trend of a 1.3 percent average annual decrease in normalized total firm sendout (Exh. HO-1, Table G-5).

1. Residential Heating Class

During the five-year forecast period, the Company projects that the number of residential customers with gas heat will increase primarily due to: (1) conversions from oil to gas heat; (2) conversions from the non-heating class; and (3) construction of new homes (Exh. HO-1, p. 3). Berkshire reports an average of 16,025 customers in 1985-86, an increase of 821 customers from the preceding year, of which over half were added as new or reactivated services while the rest were conversions (Exh. HO-S-1).

Berkshire relies upon "customer-usage factors," broken into base-use and heating-use factors, to forecast residential heating customers' sendout. In preparing base-use and heating-use factors, Berkshire states that it considers several factors including the local economy, competing fuels, conservation, and historic use factors and trends (Exh. HO-1, p. 2).

Berkshire derives base use per customer per month on a class-wide basis from sendout data during those months with zero degree days (Exh. HO-1, p. 2). The Company then adjusts the result to reflect conservation, which Berkshire assumes will reduce base use by 0.3 percent annually (Exh. HO-1, pp. 1-2).

Berkshire bases its forecast of heating use upon historical residential temperature-sensitive use (from Company billing data), adjusted for Company use and unaccounted-for gas ("UFG"). Berkshire calculates heating use per customer per degree day on a class-wide basis by subtracting the base use per customer from the total sales per customer and dividing the result by the number of degree days (Exh. HO-1, p. 2). Berkshire then decreases the heating use factor by 0.3 percent to reflect conservation (Exh. HO-1, p. 2). To calculate temperature-sensitive use, Berkshire multiplies this revised heating use factor by the number of degree days in a normal season or year and by the average number of customers (Exh. HO-1, Table G-1).

In regard to its conservation adjustment, the Company states that it expects less customer conservation in the future due to relatively stable energy prices (Exh. HO-1, p. 1). In its previous filing, the Company had adjusted both base use and heating use by one percent annually. Berkshire Gas Company, 14 DOMSC 107, 116 (1986). In the instant proceeding, however, the Company states that based on its analysis of trends in the data in EFSC Table G-1 and on informal discussions with its Marketing Department, the Company decided to decrease the conservation adjustment to 0.3 percent (Exhs. HO-C-2 and HO-C-3).

Normalized sendout in the residential with gas heating class has been decreasing in the heating season by approximately 0.7 percent annually and increasing in the non-heating season by 0.3 percent annually. Berkshire projects that sendout in the five-year forecast period will increase at 3.8 percent per year in the heating season and 3.7 percent per year in the non-heating season (Exh. HO-1, Table G-1).

2. Residential Non-Heating Class

Berkshire projects the number of residential non-heating customers to decline 3.1 percent per year, from 8,156 in 1986-87 to 7,191 in 1990-91. The Company attributes this decline to customer conversion from the non-heating class to the heating class (Exh. HO-1, p. 3).

Average use per customer in the residential non-heating class is based on the annual average use of the two most recent split years. To calculate average use, the Company employs data taken directly from the Company's billing records, which is then adjusted for Company use and UFG.

Berkshire also decreases average use per customer by approximately 0.3 percent per year to account for conservation (Exh. HO-1, pp. 2-3). Berkshire projects that average use per customer in the residential non-heating class will decline from 24.2 Mcf per customer in 1986-87 to 23.8 Mcf per customer in 1990-91, an annual compound rate of decline of 0.4 percent (Exh. HO-1, Table G-2).

3. Commercial Class

Berkshire projects that the number of commercial class customers will increase 5.5 percent per year over the forecast period from 2,985 in 1986-87 to 3,700 in 1990-91 (Exh. HO-1, Table G-3A). This exceeds the 3.1 percent commercial customer growth rate the Company projected in its previous filing. Berkshire Gas Company, 14 DOMSC 107, 121 (1986).

The Company reports commercial sendout as a single class, but recognizes that this class consists of both heating and non-heating customers, for whom separate forecasts are derived. To forecast sendout for commercial heating customers Berkshire uses the same methodology that it uses for residential heating customers, including adjustments for UFG and conservation. The sendout forecast for commercial non-heating customers is derived through the same methodology as that used for residential non-heating customers, again including adjustments for UFG and conservation. Berkshire then combines the commercial heating customer and non-heating customer sendout forecasts to produce a sendout forecast for the commercial class as a whole. Berkshire asserts that conservation will reduce base use and heating use factors by 0.3 percent per year in the commercial class throughout the forecast period (Exh. HO-1, pp. 1, 2).

Normalized firm sendout in the commercial class has been decreasing over the five-year historical period at an annual compound rate of approximately 1.2 percent during the heating season, and increasing at approximately 3.8 percent during the non-heating season. In the current filing, Berkshire projects annual compound growth rates of approximately 5.3 percent and 5.1 percent for the heating and non-heating seasons, respectively (Exh. HO-1, Table G-3A).

4. Industrial Class

The Company projects the number of firm industrial class customers to remain constant at 13 customers throughout the forecast period (Exh. HO-1, Table G-3B). In its previous filing, Berkshire projected the number of industrial customers to remain constant at 85 from 1985-86 through 1989-90. Berkshire Gas Company, 14 DOMSC 107, 121 (1986). Berkshire attributes the current forecast's lower customer number estimate to changes in classification and decreased industrial activity in its service territory (Exh. HO-1, p. 4; Table G-3B).

The Company forecasts sendout in the industrial class strictly on a use-per-customer basis, which is then decreased by 0.5 percent for the effects of conservation. The Company estimates a greater effect of conservation in the industrial class than in other classes because it perceives a historical trend of industrial customers emphasizing increased energy efficiency (Exh. HO-C-4).

The Company projects sendout to industrial customers will decline throughout the five year forecast period at an annual rate of 0.7 percent for the heating season and 0.5 percent for the non-heating season (Exh. HO-1, Table G-3B).

5. Analysis

In Condition Four of its last decision, the Siting Council ordered Berkshire to report on the accuracy of its past forecasts. Berkshire Gas Company, 14 DOMSC 107, 138, 141 (1986). In response, Berkshire filed Table FA which compares the Company's past forecast with the actual normalized sendout for those years (Exh. HO-1, Table FA). Accordingly, the Siting Council finds that Berkshire has complied with that portion of Condition Four pertaining to forecast accuracy.

Also, as part of Condition Four, the Siting Council ordered Berkshire to describe in detail and justify its approach to normalization for weather. Berkshire Gas Company, 14 DOMSC 107, 138, 141 (1986). In response, the Company states that its sendout forecast is normalized by applying monthly normal degree days to actual use factors and actual customer numbers to produce an estimate of what could have been experienced under normal weather conditions (Exh. HO-S-5). Accordingly, the Siting Council finds that Berkshire has complied with that portion of Condition Four pertaining to the normalization method.

In its previous decision, as part of Condition One, the Siting Council also ordered Berkshire to improve the documentation of its sendout forecast for the normal year by including formulae used in calculating customer use factors, customer number projections, and expanded descriptions of the forecast tables in a narrative form. See Section II.B., supra. In response, the Company provided an explanation of how it calculates base use and heating use factors (Exh. HO-S-6), as well as an example of heating use factor calculations (Exh. HO-S-11). Berkshire also provided documentation regarding customer number projections and customer use factor adjustments. Accordingly, the Siting Council finds that Berkshire has complied with that portion of Condition One pertaining to the normal year sendout methodology.

Although the Company has complied with that part of Condition One, the Company's response to this condition raises larger issues regarding the reliability of Berkshire's forecast. First, the Company has failed to establish that its customer growth projections are based on reliable data. In its filing, the Company cites two sources of regional population growth (the Berkshire Regional Planning Commission and the Franklin County Chamber of Commerce) (Exh. HO-1, p. 1), but the Company's witness testified that most of the information concerning economic and demographic conditions is obtained through conversations with the Company's Marketing Department (Tr. 9-10). Further, the Company's witness, Mr. Bianchi, testified that the customer numbers used in the forecast are the result of "verbal reports" from the Marketing Department (Tr. 11-12).[3]

Second, the Company has failed to establish that its assumptions regarding the effects of conservation are appropriate. Although Berkshire asserts that it actively supports conservation through (1) the efforts of Mass-Save and the Center for Ecological Technology, (2) the sales of high-efficiency water heaters and conversion burners, and (3) the occasional distribution of conservation literature, the Company has provided no information concerning the cost effectiveness or quantitative impact of these conservation activities (Tr. 92-95). While the Company asserts that it is promoting conservation and that conservation is occurring, Berkshire could not provide evidence to support the quantitative adjustments it makes to heating, base, and average use factors to reflect the expected impact of price-induced conservation (Tr. 8, 82, 105). In particular, although the Company's methodology assumes that conservation occurs in response to gas prices, the Company's forecasting approach does not directly account for expectations regarding price trends in the future.

3/Although Berkshire provided the results of a study which had been conducted by J. Simes, Associates, in support of the Company's customer growth projections and assumptions in the commercial and industrial classes (HO-RR-1), Mr. Bianchi stated that this study was "not specifically used" in determining customer number projections in the current filing (Tr. 21). Further, the Simes study bears no relation to the customer numbers projected by Berkshire, and the Company could neither provide data nor document the process by which this information was analyzed and incorporated into the sendout forecast.

Accordingly, while the Siting Council finds that Berkshire's normal year methodology is reviewable, it also finds that the Company has failed to establish that its assumptions regarding growth in customer numbers and the effects of conservation are valid. As a result, the Siting Council finds that the Company's normal year sendout forecast methodology is neither appropriate nor reliable.

D. Design Year

1. Description

The design year for which the Company plans is based upon 8,140 degree days (1,973 degree days during the non-heating season and 6,167 degree days during the heating season) (Exh. HO-1, Table DD). The Company has stated at different points in this proceding that the methodology used to derive this figure is based upon the following criteria: "coldest in 20 years" (Exh. HO-1, Table DD), "one standard deviation from the norm" (Tr. 88), "the accumulation of the coldest months experienced over a 20 year period" (Exh. HO-S-28), and "the coldest winter in a 30-year period" (Tr. 88). In support of its calculations, the Company submitted a study conducted for Berkshire by John Pink Associates ("Pink Weather Study") (Exh. HO-RR-4).

To forecast sendout in a design year, the Company employs the same use per customer per degree-day factors as it uses to forecast sendout in a normal year. The Company multiplies these use factors by the design heating and non-heating season degree days and by the average number of customers in each service class. The resulting sendout requirement is the amount the Company plans for under design weather conditions.

2. Analysis

In its last decision, as part of Condition One, the Siting Council ordered Berkshire to improve the documentation of its sendout forecast for the design year by including formulae used in calculating design-year and January heating-use factors, and expanded narrative descriptions of the forecast tables. See Section II.B., supra. In response, the Company provided a description and explanation of how it calculates design year use factors. Berkshire also provided sample worksheets which illustrate how these use factors are calculated (Exhs. HO-S-7 and HO-S-11). Accordingly, the Siting Council finds that Berkshire has complied with that portion of Condition One pertaining to the design year sendout methodology.

Although the Company has complied with that part of Condition One, the Company's response to this condition has raised new questions regarding the reliability of Berkshire's forecast. Berkshire employs the same use factors (heating, base and average use) to produce both a normal-year and design-year sendout forecast (Exh. HO-S-26; Tr. 83). To reflect increased consumption under design weather conditions, Berkshire simply multiplies these customer use factors by the design heating and non-heating season degree days (Tr. 85, 86). Berkshire states that it employs the same use factors in both normal and design methodologies because it believes "use factors per degree day will not change from the normal year to the design year" (Exh. HO-S-25) and that "using the higher degree days during that design period and applying it to a usage factor on an average basis reflects a different requirement" (Tr. 85).

Yet, the Company itself has determined that average use per degree day is higher during periods of cold weather (Exh. HO-S-17). For example, in its peak-day sendout forecast, the Company employs peak day use factors of the previous heating season to reflect higher use per customer per degree day and increased consumption during colder weather. See Section II.E.2., infra. Based upon such inconsistent evidence, the Siting Council finds that the Company has failed to establish that its reliance upon normal year use factors in projecting design year sendout requirements provides a reliable basis for estimating design year needs.

In Condition Four of its last decision, the Siting Council ordered Berkshire to provide a rationale for the selection of its design year criterion and an explanation of how that standard is selected. Berkshire Gas Company, 14 DOMSC 107, 138-139, 141 (1986). In response, the Company has presented numerous and often conflicting explanations and documentation which raise serious questions regarding the reliability of the Company's forecast.

To support its design year degree day criterion, the Company provided the Siting Council with several items of information. In its filing, the Company stated that the design year is the coldest year in twenty (Exh. HO-1, Table DD). At the same time, the Company's witness, Mr. Bianchi, asserted both that the design year is the coldest in thirty years and that the design year is one standard deviation from the norm (Tr. 88). However, the Pink Weather Study indicates that a one-in-twenty-years probability is determined by multiplying one standard deviation by a "safety factor" of 1.72 and adding the result to the normal year degree days (Exh. HO-RR-4, p. 3). Finally, the Company stated that its design year is the combination of the coldest months from April 1961, to March 1981 (i.e., the degree days from the coldest November over this twenty-year period plus the degree days from the coldest December over the same twenty years, etc.) (Exh. HO-S-28; Tr. 88).

The Siting Council notes initially that the Company was unable to assert whether the probability of experiencing a split year colder than 8,140 degree days is one in twenty or one in thirty. Additionally, Mr. Bianchi admitted that the Company has never experienced design weather conditions of this magnitude (Tr. 86). Therefore, the Siting Council cannot accept the Company's assumption that a design year of 8,140 degree days has a probability of occurring either once in twenty years or once in thirty years since it has, in fact, never occurred. Based upon such inconsistent evidence, the Siting Council finds that the Company has failed to establish that its reliance upon 8,140 degree days in projecting its design year requirements provides a reliable basis for estimating design year needs. Further, in light of the Company's failure to provide a consistent explanation for the selection of its design year standard, the Siting Council finds that the Company has failed to comply with that part of Condition Four pertaining to its design year standard.

The Siting Council also finds that the Company has failed to establish that its assumptions regarding the effects of conservation for the design year are appropriate. As discussed in Section II.C.5., supra, the Company was unable to document its conservation assumptions. While the Company asserts that it promotes conservation and that conservation is occurring, Berkshire makes quantitative adjustments to heating, base, and average use factors to reflect conservation (which the Company asserts is in response to price) without showing how these adjustments were derived (Tr. 8, 82, 105).

Accordingly, while the Siting Council finds that Berkshire's design year methodology is reviewable, it also finds that the Company has failed to establish that its design year standard and its assumptions regarding the effects of conservation on the design year are valid. As a result, the Siting Council finds that the Company's design year sendout forecast methodology is neither appropriate nor reliable.

E. Peak Day

1. Description

Berkshire defines a peak day as the coldest day which is likely to occur during the forecast period. The Company states it uses a 74-degree-day standard when planning for a peak day, which is both "12.5% colder than the average temperature of the coldest day in each of the previous 30 years" (Exh. HO-1, p. 3) and "coldest by 1 standard deviation from average coldest day expected to occur once in 30 years" (Exh. HO-1, Table DD).

Berkshire projects peak day sendout using historical degree-day and sendout data recorded on the most recent heating season's peak day and adjusted to reflect the 74-degree-day standard. The Company adjusts this estimate to reflect expected usage associated with projected customer additions or subtractions for each customer class. Finally, the Company further applies a conservation factor to the historic peak day usage (Exh. HO-S-9).

2. Analysis

In Condition Four of its last decision, the Siting Council ordered Berkshire to provide a rationale for the selection of its peak day criterion and an explanation of how that standard is selected. Berkshire Gas Company, 14 DOMSC 107, 138-139, 141 (1986). In responding to Condition Four, the Company provided inconsistent explanations and documentation for its choice of the 74-degree-day standard. This inconsistency raises serious questions regarding the reliability of the Company's forecast.

The Company states that its 74-degree-day standard was selected as the "coldest [day] by one standard deviation from the average coldest day between April 1951 and March 1981" because one standard deviation "produces the probability of occurrence once in twenty years" (Exh. HO-S-30). However, as noted in Section II.D.2. supra, the Company's Pink Weather Study indicates that a one-in-twenty-years probability is determined by multiplying one standard deviation by a "safety factor" of 1.7 and adding the result to the average coldest degree day (Exh. HO-RR-4, p. 3). Further, the Company states that 74 degree days is "12.5% colder than the average temperature of the coldest day in each of the previous 30 years" (Exh. HO-1, p. 3). It is not clear whether this is a characteristic of the standard chosen by the stated statistical criterion or whether this is a different methodology. Based upon conflicting and incomplete evidence, the Siting Council finds that the Company has failed to establish that its peak day standard is reliable. Further, in light of the Company's failure to provide a valid basis for the selection of its peak day standard, the Siting Council finds that the Company has failed to comply with that portion of Condition Four pertaining to the peak day standard.

In its last decision, as part of Condition One, the Siting Council also ordered the Company to improve its peak day sendout forecast documentation. See Section II.B., supra. In response, Berkshire provided a narrative description of its peak day methodology, accompanied by supporting calculations. Accordingly, the Siting Council finds that Berkshire has complied with that part of Condition One pertaining to its peak day sendout forecasting methodology.

In the past, the Siting Council repeatedly has criticized Berkshire's peak day methodology for its failure to separate base use from heating use in projecting customer load growth and for the manner in which conservation adjustments were made. Berkshire Gas Company, 14 DOMSC 107, 124 (1986); Berkshire Gas Company, 10 DOMSC 127, 137 (1984). In the instant case, the Siting Council again questions the appropriateness of Berkshire's peak day forecast methodology, which employs average use factors rather than heating and base use factors. The Company acknowledges that average use per degree day is higher during periods of cold weather (Exh. HO-S-17). See Section II.D.3., supra. But, because the Company bases its peak day sendout projections on average-use factors rather than upon base- and heating-use factors, the Siting Council cannot determine whether Berkshire's peak day methodology appropriately captures increased consumption that the Company itself believes takes place. Based on the documentation provided, the Siting Council can only determine that there is an inconsistency in the way the Company treats consumption during colder weather in its design year and peak day sendout methodologies.

In addition, the Siting Council rejects, for several reasons, the Company's adjustment for conservation in its peak day forecast methodology. First, as discussed in Sections II.C.3. and II.D.2. supra, the Company makes undocumented and unsubstantiated quantitative assumptions regarding the impact of conservation on customer use factors. Second, Berkshire assumes a constant conservation factor of -0.3 percent for all classes in its peak day methodology, even though it assumes a -0.5 percent adjustment for the industrial class in its normal and design year methodologies (See Section II.C.4., supra). Third, the Company combines actual peak sendout from the previous heating season with the estimate of peak sendout attributable to new customers and adjusts the results for conservation, thereby adjusting the previous heating season's peak sendout twice for the effects of conservation. Fourth, the Company applies its -0.3 percent conservation factor to total peak day sendout rather than to the individual peak day customer use factors in each class. This results in a slight downward bias of the Company's peak day sendout forecast. Finally, the Company provides no documentation supporting its assumption that conservation will similarly reduce sendout during both a normal year and a peak day. The Company observes that higher gas consumption per degree day occurs during the coldest weather (Exh. HO-S-17) and yet acknowledges it has no method of determining exactly what the effects of conservation will be on a peak day (Tr. 38).

Accordingly, while the Siting Council finds that Berkshire's peak day sendout methodology is reviewable, the Siting Council also finds that the Company has failed to establish that its peak day standard and its assumptions regarding the effects of conservation are valid. As a result, the Siting Council finds that the Company's peak day forecast methodology is neither appropriate nor reliable.

F. Summary

In summary, the Siting Council finds that the Company has complied with Condition One of its previous decision. In addition, the Siting Council finds that the Company has complied with all portions of Condition Four relating to the sendout forecast with the exception of those parts of the condition relating to Berkshire's design year and peak day forecasts.

At the same time, the Siting Council finds that the Company has provided minimally acceptable documentation in support of its normal year, design year and peak day sendout forecasts. While this documentation allows the Siting Council to review the Company's forecast, the Siting Council has determined that each of the forecast methodologies is inappropriate and unreliable. Accordingly, the Siting Council finds that Berkshire's forecast of sendout requirements does not provide a sound basis for resource planning decisions.

Accordingly, the Siting Council hereby rejects the Company'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. Berkshire Gas Company, 14 DOMSC 107, 128 (1986); Holyoke Gas and Electric Light Department, 15 DOMSC 1, 27 (1986); Fitchburg Gas and Electric Light Company, 15 DOMSC 39, 54 (1986); Westfield Gas and Electric Light Department, 15 DOMSC 67, 72 (1986); Fall River Gas Company, 15 DOMSC 97, 111 (1986). 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 transportation projects that are 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.[4]

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.

4/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, EFSC 84-25, 16 DOMSC __, 33 (1986); Fitchburg Gas and Electric Light Company, 15 DOMSC 39, 53 (1986); Fall River Gas Company, 15 DOMSC 97, 115 (1986); Berkshire Gas Company, 14 DOMSC 107, 127 (1986); Bay State Gas Company; 14 DOMSC 143, 168 (1986); Essex County Gas Company, 14 DOMSC 189, 201-202 (1986).

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.

The Siting Council also reviews the <u>cost</u> of a utility's supply plan in terms of cost minimization, subject to trade-offs with adequacy of supplies.

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. <u>Berkshire Gas Company</u>, 14 DOMSC 107, 128 (1986).

B. <u>Prior Supply Conditions</u>

In its previous decision, the Siting Council approved Berkshire's supply plan subject to two conditions, Condition Two and Condition Three:

> 2) That Berkshire provide a detailed update on the status of the DOMAC [Distrigas of Massachusetts Corporation] supply source and to specify (if necessary) its contingency plan for meeting sendout requirements in a normal and design year and on a peak day if DOMAC LNG [liquefied natural gas] supplies are not available as expected;

3) That the Company resolve any discrepancies in its comparison of resources and requirements for the normal year heating seasons in each of the years 1985-86 through 1988-89. Berkshire Gas Company, 14 DOMSC 107, 141 (1986).

In addition, in Condition Four of its previous decision, the Siting Council ordered Berkshire to comply with the Siting Council's Order in Evaluation of Standards and Procedures for Reviewing Sendout Forecasts and Supply Plans of Natural Gas Utilities, 14 DOMSC 95, 104 (1986) and that Order's implementation in Administrative Bulletin 86-1. Berkshire Gas Company, 14 DOMSC 107, 141 (1986).

Berkshire's compliance with these conditions is discussed in Sections III.C. through III.F., infra.

C. Resources

Berkshire currently has three general categories of gas supplies for meeting customers' firm requirements: 1) pipeline gas -- that is, gas purchased from and delivered by Tennessee, and gas stored in out-of-state underground facilities and transported to the Company by Tennessee; 2) LNG sold to Berkshire by Bay State; and 3) propane purchased from the Warren Petroleum Company and vaporized at Company facilities located in Pittsfield, Stockbridge, North Adams, Greenfield, and Hatfield. These supply categories are described below.

1. Pipeline Gas and Storage Services

Berkshire states that it is awaiting an increase in the Company's CD-6 annual volumetric limitation ("AVL") from Tennessee from 5,257 MMcf to 5,634 MMcf and in its maximum daily quantity ("MDQ") from 20 MMcf to 25 MMcf (Tr. 63). As of the date of the hearing, the Company stated that it did not intend to file with the Federal Energy Regulatory Commission ("FERC") for this increase before Spring 1987, and that this filing may depend upon the outcome of the current FERC proceeding in Docket RP86-116 regarding Tennessee's contractual obligations. The Company further states that Tennessee has indicated that these proceedings could allow for construction to be completed as early as November 1, 1988 (Exhs. HO-R-1 and HO-R-2).

Because of this delay in the "AVL" project, Tennessee and certain distribution customers including Berkshire have entered into a Settlement Agreement regarding firm transportation of storage gas. FERC approved the Settlement Agreement insofar as Tennessee was granted authority to transport Penn-York and Consolidated storage gas volumes up to 4.9 MMcf per day (Exh. HO-1, Table G-24) to Berkshire on a firm basis. Tennessee Gas Pipeline Company, FERC Docket No. CP84-441-020.[5]

Berkshire states that it is also a party to an agreement for Canadian gas as part of Phase 2 of the Boundary Gas Project ("Boundary"). As proposed, Berkshire's MDQ in the Boundary project would be 1.05 MMcf with an AVL of 383 MMcf (Exh. HO-1, Table G-15; Exh. HO-R-6). Because of a delay in this project, however, Tennessee has filed an application with FERC for authorization to provide interim sales of natural gas to Boundary customers until the facilities necessary to import gas from Canada are constructed. Tennessee would sell gas to those customers, including Berkshire, under the CD-5 and CD-6 rate schedules. This project, known as Interim Natural Gas Service ("INGS"), is pending FERC approval (FERC Docket No. CP86-251). The Company expects to begin receiving its Boundary MDQ and AVL through INGS on November 1, 1987, and will continue to receive these volumes until it receives Boundary volumes on a firm basis (Tr. 67-68).

2. Liquefied Natural Gas

In the past, the Company purchased LNG from DOMAC through a displacement contract with Boston Gas Company. The Company's current AVL (290 MMcf) and MDQ (1.3 MMcf) contract with DOMAC is due to expire on December 1, 1997 (Exh. HO-1, Table G-24).

5/In this proceeding, the Siting Council has taken administrative notice of Tennessee Gas Pipeline's filing in the FERC Docket No. CP84-441-020.

In response to Condition Two of the previous Siting Council decision regarding the reliability of these DOMAC supplies (see Section III.B., supra), Berkshire states that DOMAC had been attempting to establish a ship schedule for the 1986-87 winter season, but at the time of this filing such a schedule had not been established. Berkshire states that it has not expressed any interest in DOMAC supplies due to the availability of increased supplies from other sources and therefore has not included any DOMAC volumes in its supply plan (Exh. HO-1). While Condition Two of the previous decision required Berkshire to file a contingency plan in the event that DOMAC supplies were not available, the elimination of DOMAC LNG from the Company's current supply plan is tantamount to compliance with Condition Two. Accordingly, the Siting Council finds that Berkshire has complied with Condition Two of the Siting Council's previous decision.

Berkshire also has a contract with Bay State for an annual supply of 205 MMcf of LNG, of which the Company can obtain a maximum of 4 MMcf per day (Exh. HO-1, Table G-24). Last year Berkshire took 120 MMcf of its total available quantity (Exh. HO-R-12).

Berkshire's contract with Bay State expires on March 31, 1988. Mr. Bianchi indicates that the Company currently has no plans to renew this contract (Tr. 79). In fact, Berkshire anticipates that these Bay State volumes will be replaced, in part or in whole, with volumes received through Tennessee's expansion program (Exh. HO-R-13). However, Berkshire states that should Tennessee's system expansion plan be cancelled or modified, the Company would negotiate with Bay State for a revised contract of shorter duration and reduced volumes to meet sendout requirements (Exh. HO-R-13). The Company states that it could also use propane on an interim basis to help meet sendout requirements in the absence of Bay State LNG (Exh. HO-R-13).

3. Propane

Berkshire has a one year contract with the Warren Petroleum Company for liquid propane. This contract for 800,000 gallons per year (73.5 MMcf) with the option for an additional 800,000 gallons, can be renewed on an annual basis each April (Exh. HO-1, Table G-24).

In addition, Berkshire has five liquid propane-air facilities at various locations within its service territory. Total storage capacity for all facilities combined is 65.5 MMcf with a total vaporization capacity of 13.7 MMcf per day for the next two years and 14.8 MMcf per day for the following three years of the forecast (Exh. HO-1, Table G-14).

D. Adequacy of Supply

In reviewing Berkshire's current supply plan, the Siting Council must determine whether the Company has adequate resources to meet projected sendout requirements under a reasonable range of contingencies. In order to make this determination, the Siting Council examines whether the Company's "base case" resource plan is adequate (1) to meet firm sendout requirements under normal, design, peak day, and cold snap weather conditions, and (2) to meet those firm sendout requirements under a reasonable range of supply contingencies.

If the Siting Council determines that the Company's "base case" plan is not adequate to meet sendout under a reasonable range of contingencies, the Company must establish that it has an action plan to meet those projected firm sendout requirements.

1. Base Case Supplies

a. Normal Year

In a normal year, Berkshire must have adequate supplies to meet several types of requirements. Above all, Berkshire must meet the requirements of its firm customers. In addition, the Company must ensure that its underground storage facilities are filled prior to the start of the heating season. To the extent possible, Berkshire also supplies gas to its interruptible customers.

In response to Condition Three of the previous Siting Council decision, the Company has provided a filing in which its EFSC G-22 Tables balance resources with requirements, leaving no supply deficiencies in any year. Accordingly, the Siting Council finds that Berkshire has complied with Condition Three of the previous decision.

In the upcoming heating seasons, the Company plans to meet firm customer requirements, limited interruptible sales, and minor fuel reimbursement needs by using its firm Tennessee CD-6 pipeline supplies, underground storage return gas, firm LNG purchases, and stored propane (See Table 2). In addition, the Company expects to have 158 MMcf available through INGS beginning in the 1987-88 heating season. In the non-heating seasons, Berkshire plans to meet its firm requirements, refill underground storage, and make sales to interruptible customers by using CD-6 pipeline supplies from Tennessee and INGS volumes (See Table 3).

Accordingly, the Siting Council finds that the Company's base case supply plan is adequate on a seasonal basis to meet its sendout requirements in the heating and non-heating seasons of the normal year.

b. Design Year

During a design year, Berkshire must have sufficient gas supplies to meet the sendout requirements of its firm customers. Berkshire's ability to meet increased sendout requirements during a design heating season depends upon actual daily sendout developments throughout the heating season. A company may not be able to use its total available quantity of storage return gas if volumes of storage gas not taken in the early part of the heating season cannot be transported to the Company's service territory because of daily transportation limitations in the rest of the heating season. Similarly, use of supplemental fuels may be dictated largely by the weather and the daily dispatch pattern throughout the heating season. Berkshire Gas Company, 14 DOMSC 107, 132-135 (1986). In the event that Berkshire does not receive full storage return gas or LNG volumes, the Company can reduce sales to interruptible customers to meet firm customer requirements.

In a design heating season, Berkshire plans to use Tennessee CD-6 supplies, storage volumes, LNG volumes, spot market propane purchases and stored propane to meet increased system requirements (See Table 4).

In a design non-heating season, Berkshire expects sendout to firm customers to be greater than in a normal non-heating season due to the temperature-sensitive requirements of those customers (See Table 5). Berkshire anticipates no change in interruptible sales in a design non-heating season as compared to a normal non-heating season. Berkshire expects to meet the net additional needs in a design non-heating season through increasing its take of Tennessee CD-6. Additionally, with the INGS volumes planned to become available in November 1987, Berkshire expects to have excess CD-6 pipeline supplies to meet any unanticipated sendout requirements. If required, Berkshire can reduce its interruptible sales to meet firm or storage refill requirements.

Accordingly, the Siting Council finds that Berkshire's base case supply plan is adequate on a seasonal basis to meet its sendout requirements in the heating and non-heating seasons of a design year.

c. Peak Day

Berkshire must have adequate sendout capacity to meet the requirements of its firm customers on a peak day. While total supply capability necessary for meeting normal and design year requirements is a function of the aggregate volumes of gas available over some contract period, peak day supply capability is determined by the maximum daily deliveries of firm pipeline gas and the maximum rate at which supplementals may be dispatched.

Table 6 summarizes Berkshire's peak day resources and requirements over the forecast period. The peak day for which the Company plans reflects the energy requirements on a 74 degree-day basis, as discussed in Section II.E.1., supra. Berkshire has supplies available in excess of the system's firm peak day requirements throughout the five-year forecast period. In fact, Mr. Bianchi testified that, on average, Berkshire currently has supplies in excess of twenty percent of forecasted peak day requirements (Tr. 77).

Given the excess resources the Company has available, the Siting Council finds that Berkshire's base case supply plan is adequate to meet its firm peak day sendout requirements.

d. Cold Snap

In Condition Four of its last decision, the Siting Council ordered Berkshire to provide an analysis of its cold snap preparedness or an explanation of why such an analysis is unnecessary. Berkshire Gas Company, 14 DOMSC 107, 139 (1986). In response, the Company submitted an analysis describing its resources and the manner in which they could be used to meet a protracted period of design or near-design weather (Exh. HO-R-14).

The Siting Council has defined a cold snap as a prolonged series of days at or near peak conditions. Berkshire Gas Company, 14 DOMSC 107, 137 (1986). For supply planning purposes, Berkshire considers a cold snap to be a period of sendout at or near peak conditions for approximately eight to fourteen days (Exh. HO-R-14). The Company's ability to meet such a cold snap is tied to its ability to meet design heating-season requirements and its ability to meet peak-day sendout requirements. The Company must demonstrate that the aggregate resources available to it are adequate to meet the near maximum level of sendout over a sustained period of time, and that it has and can sustain the ability to deliver large daily volumes.

Berkshire is well prepared to meet the daily sendout requirements associated with an extended cold snap lasting from eight to fourteen days (Exh. HO-R-14). Of those peak day resources available to Berkshire, approximately 69 percent are firm pipeline deliveries: Tennessee CD-6 (48.5 percent of peak day resources available); Bay State LNG (9.5 percent); and underground storage (11 percent). Berkshire plans to meet the remaining 31 percent of its daily peak-day requirements with propane.

Although this propane supply is not automatically refilled to full capacity on a daily basis without action by the Company, Berkshire has approximately five days of on-site propane storage available at its each of five propane plants assuming vaporization at approximately 75 percent of capacity (Exh. HO-R-14). Maintaining storage levels at or near capacity would require approximately 15 truck loads of propane to be delivered to such sites on a daily basis. Berkshire states that because its service territory is located only 40 miles from the Selkirk, New York propane facility, the Company can order, receive deliveries, and unload in excess of 50 truck loads of propane in a 24-hour period. Although Berkshire relies upon propane trailers belonging to other suppliers, the Company owns four such trailers which remain available to it on a 24-hour basis during cold snap conditions (Exh. HO-R-14).

The combination of these supplies and transportation capability would allow Berkshire to meet firm requirements during a cold snap. Accordingly, the Siting Council finds that Berkshire has adequate resources to meet its firm forecasted sendout requirements under cold snap conditions and has complied with that portion of Condition Four pertaining to the cold snap analysis. Further, the Siting Council ORDERS Berkshire in its next filing to submit an updated cold snap analysis. See Section IV, infra.

2. Contingency Analysis

In determining the adequacy of a company's supply plan, the Siting Council identifies certain key contingencies and evaluates the impact on the company's ability to meet forecasted requirements if such contingencies occur. For example, even if certain existing resources were unavailable due to delivery problems or if certain planned new supplies were delayed or cancelled, a company would still have to demonstrate that it has adequate resources to meet projected firm sendout requirements.[6] If the Company cannot establish that it has adequate resources in the event that certain identified resources are not available, Berkshire must then demonstrate that it has an action plan to meet sendout requirements in the absence of those resources.

6/ In the instant case, the Siting Council's contingency analysis focuses on the Company's ability to meet peak day sendout requirements in the event that certain new resources are delayed or unavailable during the forecast period. For other gas companies, other critical contingency and planning periods might be appropriate.

In the case of Berkshire, the Siting Council's analysis focuses on those resources which the Company plans to add during the forecast period. Specifically, the Siting Council identifies as planning contingencies the supplies associated with the Tennessee expansion project and the INGS project, since these two projects have already experienced a pattern of delays (See Section III.C.1, supra).

In the instant proceeding, the Company first indicated that it was possible for the Tennessee expansion project to provide an increased MDQ and AVL by November 1, 1988 (Exhs. HO-R-1 and HO-R-2). The Company's witness, however, stated that the 1989-1990 split year would be a more realistic time frame in terms of the final development of this project (Tr. 63). If the Tennessee expansion project is not available through the entire forecast period, Berkshire would barely meet peak day sendout requirements in 1989-1990, and would have a 1.3 MMcf shortfall in 1990-1991. The Company, however, has stated that it would be able to secure an extension of the Bay State LNG contract at a volume of 2 MMcf per day for the last two years of the forecast period (Exh. HO-1, Table G-23; Tr. 79-80). This extension would enable the Company to maintain sufficient reserves during 1989-1990 and have a 0.7 MMcf excess over peak day sendout requirements in 1990-1991. Accordingly, the Siting Council finds that Berkshire's intention to secure an extension of its Bay State LNG contract constitutes a satisfactory action plan for securing supplies to meet peak day requirements throughout the forecast period in the event that the Tennessee expansion project is delayed or cancelled.

Berkshire anticipates that it will begin receiving volumes of Canadian gas through INGS at the beginning of the 1987-88 heating season and will continue until Phase 2 of the Boundary project is finalized. See Section III.C.1., supra. The Company's witness, Mr. Bianchi, stated that construction of the facilities necessary for INGS is progressing and that the Company was "confident" that November 1, 1987 was an "extremely realistic target" (Tr. 67-68). If the INGS project were not available throughout the forecast period, Berkshire would still have surplus peak day supplies throughout the forecast period (See Table 6). Accordingly, the Siting Council finds that Berkshire has adequate resources to meet peak day requirements throughout the forecast period in the event that INGS is delayed or cancelled.

3. Conclusions on the Adequacy of Supply

The Siting Council has found that the Company has adequate resources to meet "base case" sendout requirements in the normal year, design year, on a peak day and under cold snap conditions. The Siting Council has also found that if the INGS project is not available, the Company still has adequate resources to meet its peak day sendout requirements during the entire forecast period. Further, the Siting Council has found that if the Tennessee expansion project is delayed throughout the entire forecast period, the Company has an action plan for securing supplies to meet peak day sendout requirements during the fourth and fifth year of its forecast.

Accordingly, the Siting Council finds that the Company has adequate resources to meet its sendout requirements during the forecast period.

E. Least-Cost Supply

1. Adequacy/Cost Tradeoff

In this particular case, the Siting Council has found that the Company has adequate resources to meet its forecasted requirements under normal, design, and peak day conditions. In reaching this conclusion, however, the Siting Council makes three observations relating directly or indirectly to the cost of Berkshire's supplies.

First, the Company plans for sufficient supplies to meet the estimated requirements of firm customers even though its estimate is based upon an unreliable and perhaps inflated projection of customer growth. The Company could not document its customer growth projections and acknowledged that the accuracy of its estimates varies with the size of the customer class (Tr. 14, 24). Since the Siting Council rejected the Company's projection of customer numbers as unreliable, it follows that the Siting Council must scrutinize whether

Berkshire's supply plan minimizes cost since the plan relies upon unreliable (and, arguably, inflated) customer numbers as a basis for projecting sendout requirements and, in turn, as a guide for making resource planning decisions.

Second, since the Siting Council rejected the Company's design year and peak day criteria as inappropriate, the Siting Council must scrutinize whether Berkshire's supply plan minimizes cost when, as is the case here, the Company uses those criteria to make resource planning decisions.

Finally, Berkshire currently plans a supply mix designed to maintain, on average, firm resources in excess of 20 percent above peak day requirements -- a situation that even the Company's witness described as "more than adequate to meet design needs" (Tr. 77-79). The Company's planning for and maintenance of 20-percent excess is particularly troublesome to the Siting Council in light of the concerns noted above regarding customer numbers and unsupported design-year and peak-day criteria that could overstate the Company's forecast of sendout requirements.

The Company's reliance upon an overly conservative supply planning standard and its near exclusive emphasis upon reliability concerns raise serious questions about whether the Company's supply plan maintains sufficient focus on the other objective of minimizing cost. While the Siting Council recognizes that reliability and cost objectives can often come into conflict and must therefore be carefully balanced, the Siting Council nonetheless must ensure that a company's supply planning meets both objectives in an acceptable manner.

2. Supply Cost Analysis

The Siting Council recently articulated its concerns regarding the need for gas companies to engage in least-cost planning. In its Order in Docket No. 85-64, 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 the 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 needs, since options with similar reliability may have different costs and vice versa, and since different load additions with varying gas usage patterns impose different kinds of supply obligations in terms of cost.

In its most recent decision regarding Berkshire, the Company was ordered to comply with the Siting Council's Decision in Docket No. 85-64 and its implementation in Administrative Bulletin 86-1. Specifically, to enable the Siting Council to ensure the the Company's supply plan minimizes cost, the Company was ordered to perform an internal study comparing the costs of a reasonable range of practical supply alternatives if its filing indicated the addition of a long-term firm gas supply contract. Berkshire Gas Company, 14 DOMSC 107, 141 (1986).

In the instant case, the Company's obligation to perform such a study was triggered by Berkshire's decision to add new Tennessee and Boundary volumes during the five-year forecast period. Specifically, 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, however, did not perform the required cost studies (Exh. HO-R-15; Tr. 66-68). Berkshire's supply planning process then seems to consist of judgmental decisions by Company management without benefit of any formal analysis of the costs and benefits of alternative supply configurations.

In the absence of any cost study, the Siting Council draws several conclusions. First, Berkshire has clearly failed to comply with a direct Siting Council order. More importantly in the final analysis, Berkshire's 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 the Company management to determine what, if any, amounts of the proposed new supplies from the Tennessee expansion and Boundary 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 (1) the Company has failed to comply with that portion of Condition Four of the last Siting Council decision that required the performance of cost studies, and (2) the Company has failed to establish that the Tennessee expansion and Boundary projects represent least-cost additions to the Company's supply plan.

3. Comparison of Alternatives on an Equal Footing

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 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 plan minimizes cost, the Siting Council also evaluates whether the company's supply planning process adequately considers alternative resource additions, including demand-side options, on an equal basis. Fall River Gas Company, 15 DOMSC 97, 115 (1986).

In this case, the Company was unable to establish how it evaluates the costs and benefits of Company-sponsored conservation strategies against the costs and benefits of obtaining new supplies. Berkshire provided testimony and documentation that it has been active historically in the promotion of conservation through the sale of energy efficient appliances and accessories, the distribution of conservation literature, and the contribution of funding for the conservation programs operated by Mass-Save and the Center for Ecological Technology (Exh. HO-1, p. 1; Tr. 93-100). However, although the Company minimally contributes to conservation programs, Berkshire failed to provide any testimony or evidence regarding the costs and benefits to the system that are associated with these activities.

Accordingly, the Siting Council finds that the Company's supply plan fails to even consider whether conservation and load mangement are reliable or cost-justified means of marginally reducing sendout during different seasons of the year, as an alternative to adding new supplies to meet these marginal sendout requirements. In making this finding, the Siting Council does not so much question whether Berkshire should operate these programs in the first place -- since they may well be cost-justified -- but moreover criticizes the Company for failing to evaluate conservation and load-management programs' potential as possible resource options available to the Company.

Therefore, the Siting Council finds that the Company has failed to establish that it treats all resource options on an equal footing in its planning process, since that process fails to incorporate conservation and load management.

4. Conclusions

Based on the foregoing, the Siting Council finds that (1) the Company has failed to comply with that portion of Condition Four of the previous Siting Council decision that required the performance of cost studies, (2) the Company has failed to establish that the Tennessee expansion and Boundary projects represent least-cost additions to the Company's supply plan, and (3) the Company has 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 and to distinguish between them on the basis of cost.

Accordingly, the Siting Council finds that the Company's supply plan fails to ensure a least-cost energy supply.

F. Summary of the Supply Plan Analysis

While the Siting Council determined that the Company's supply plan is adequate, the Siting Council has found that Berkshire's supply plan fails to ensure a least-cost energy supply.

Accordingly, the Siting Council rejects Berkshire's 1986 supply plan.

IV. Order

The Siting Council hereby REJECTS the sendout forecast and supply plan filed by the Berkshire Gas Company as its Fourth Supplement to the Second Long-Range Forecast of Natural Gas Requirements and Resources.

The Siting Council ORDERS the Company to include in its next filing an updated cold-snap analysis.

The Siting Council FURTHER ORDERS the Company to file its next long-range forecast on December 1, 1987.

Robert D. Shapiro

Robert D. Shapiro
Hearing Officer

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of July 28, 1987, by the members and designees present and voting: Sharon M. Pollard (Secretary of Energy Resources); Sarah Wald (for Paula W. Gold, Secretary of Consumer Affairs); Fred Hoskins (for Joseph D. Alviani, Secretary of Economic and Manpower Affairs); Joseph W. Joyce (Public Labor Member). Ineligible to vote: Elliot J. Roseman (Public Oil Member); Stephen D. Umans (Public Electricity Member). Absent: Stephen Roop (for James S. Hoyte, Secretary of Environmental Affairs); Madeline Varitimos (Public Environmental Member); Dennis J. LaCroix (Public Gas Member).

Sharon M. Pollard
Chairperson

7/30/87
Date

TABLE 1

Berkshire Gas Company

Forecast of Sendout by Class

Normal Year

Customer Class	1986 - 87 Nonheating Season (MMcf)	1986 - 87 Heating Season (MMcf)	1986 - 87 Percentage of Annual Firm Sendout (%)	1990 - 91 Nonheating Season (MMcf)	1990 - 91 Heating Season (MMcf)	1990 - 91 Percentage of Annual Firm Sendout (%)
Residential Heating	745	1,448	48.4	861	1,680	48.6
Residential Nonheating	115	82	4.3	100	71	3.3
Commercial	619	970	35.1	755	1,194	37.3
Industrial	194	138	7.3	190	134	6.2
Company Use and Unaccounted For	97	122	4.8	106	140	4.7
Total Firm Sendout	1,770	2,760	100.0	2,012	3,219	100.0
Interruptible	650	200	-	650	200	-
Total Sendout	2,420	2,960	-	2,662	3,419	-

Source: Exhibit HO-1.

TABLE 2

Berkshire Gas Company

Comparison of Resources and Requirements

(MMcf)

Normal Year - Heating Season

Requirements	1986 - 87	1987 - 88	1988 - 89	1989 - 90	1990 - 91
Normal Firm Sendout	2,760	2,880	3,000	3,104	3,220
Interruptibles	200	200	200	200	200
Fuel Reimbursement	6	6	7	7	7
Total	2,966	3,086	3,207	3,311	3,427
Resources					
TGP CD-6	2,503	2,447	2,606	2,692	2,799
Boundary*	0	158	158	158	158
TGP Storage Return	297	315	333	351	360
Firm LNG Purchases	146	146	90	90	90
LP From Storage	20	20	20	20	20
Total	2,966	3,086	3,207	3,311	3,427
Surplus/Deficit	0	0	0	0	0

* Boundary Interim Natural Gas Service provided by Tennessee

Source: Exhibit HO-1.

TABLE 3

Berkshire Gas Company

Comparison of Resources and Requirements

(MMcf)

Normal Year - Nonheating Season

Requirements	1987	1988	1989	1990	1991
Normal Firm Sendout	1,770	1,835	1,898	1,953	2,012
Interruptibles	650	650	650	650	650
Fuel Reimbursement	0	0	0	0	0
Storage Refill:					
- Underground	330	350	370	390	400
- Propane	35	40	45	50	55
- Liquefaction	0	0	0	0	0
- LNG Purchases	0	0	0	0	0
Total	2,785	2,875	2,963	3,043	3,117

Resources	1987	1988	1989	1990	1991
TGP CD-6	2,785	2,650	2,738	2,818	2,892
Boundary*	0	225	225	225	225
Total	2,785	2,875	2,963	3,043	3,117
Surplus/Deficit	0	0	0	0	0

* Boundary Interim Natural Gas Service provided by Tennessee

Source: Exhibit HO-1.

TABLE 4

Berkshire Gas Company

Comparison of Resources and Requirements

(MMcf)

Design Year - Heating Season

Requirements	1986 - 87	1987 - 88	1988 - 89	1989 - 90	1990 - 91
Design Firm Sendout	2,940	3,069	3,199	3,310	3,434
Interruptibles	200	200	200	200	200
Fuel Reimbursement	7	7	7	8	8
Total	3,147	3,276	3,406	3,518	3,642
Resources					
TGP CD-6	2,762	2,708	2,813	2,900	3,009
TGP Storage Return	330	350	370	390	400
Boundary*	0	158	158	158	158
LP From Storage	35	40	45	50	55
LP Spot Purchases	20	20	20	20	20
Total	3,147	3,276	3,406	3,518	3,642
Surplus/Deficit	0	0	0	0	0

* Boundary Interim Natural Gas Service provided by Tennessee

Source: Exhibit HO-1.

TABLE 5

Berkshire Gas Company

Comparison of Resources and Requirements

(MMcf)

Design Year - Nonheating Season

Requirements	1987	1988	1989	1990	1991
Design Firm Sendout	1,806	1,872	1,938	1,994	2,055
Interruptibles	650	650	650	650	650
Fuel Reimbursement	0	0	0	0	0
Storage Refill					
- Underground	330	350	370	390	400
- Propane	35	40	45	50	55
Total	2,821	2,912	3,003	3,084	3,160
Resources					
TGP CD-6	2,821	2,687	2,778	2,859	2,935
Boundary*	0	225	225	225	225
Total	2,821	2,912	3,003	3,084	3,160
Surplus/Deficit	0	0	0	0	0

* Boundary Interim Natural Gas Service provided by Tennessee

Source: Exhibit HO-1.

TABLE 6

Berkshire Gas Company

Comparison of Resources and Requirements

Peak Day

(MMcf/Day)

Requirements	1986 - 87	1987 - 88	1988 - 89	1989 - 90	1990 - 91
Forecasted Sendout	36.8	38.1	39.4	40.6	41.9
Resources					
TGP CD-6	19.9	19.9	19.9	19.9	19.9
TGP Expansion Project	0	0	0	4.9	4.9
TGP Storage Return	4.9	4.9	4.9	4.9	4.9
Propane	13.8	13.8	14.8	14.8	14.8
Vaporized LNG Purchase from Bay State	4.0	4.0	0	0	0
Boundary*	0	1.0	1.0	1.0	1.0
Total	42.6	43.6	40.6	45.5	45.5
Surplus/Deficit	5.8	5.5	1.2	4.9	3.6

* Boundary Interim Natural Gas Service provided by Tennessee

Source: Exhibit HO-1.

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 service of the decision, order or ruling of the Siting Council or within such further time as the Siting Council may allow upon request filed prior to the expiration of 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. (Sec. 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 the Massachusetts Municipal Wholesale Electric Company for Approval of its 1985 Long-Range Forecast of Electricity Needs and Resources on behalf of its Thirty-Three Members	)	EFSC 85-1

FINAL DECISION

Robert Shapiro
Hearing Officer
July 9, 1987

On the Decision:

Susan Tierney
John Dalton

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The Energy Facilities Siting Council ("Siting Council") hereby APPROVES the demand forecast and REJECTS the supply plan filed by the Massachusetts Municipal Wholesale Electric Company ("MMWEC" or "the Company") on behalf of its thirty-three members for the ten years from 1985 through 1994.

I. INTRODUCTION

A. Description of the Company

MMWEC is a public corporation of the Commonwealth, created under Chapter 775 of the Acts of 1975. MMWEC provides a range of supply planning and demand forecasting services to 33 municipally owned electric systems ("members" or "member systems") in Massachusetts.[1] MMWEC's joint planning activities include: preparing load forecasts for individual members; assisting in the analysis and implementation of load management and conservation programs; financing and owning generating resources; contracting for power supplies; and providing coordination with the New England Power Pool ("NEPOOL") (Exh. HO-1, pp. I.1-I.2).

In 1985, the 33 member systems experienced a non-coincident peak demand of 834 megawatts ("MW") and sold approximately 4.1 million megawatt hours ("MWH") of electricity to over 210,000 customers in a noncontiguous service area. MMWEC, through its members, serves approximately ten percent of the electric load in Massachusetts (Tr. I, pp. 6-8).

MMWEC asserts that its planning efforts are guided by the

1/In its 1985 Forecast, MMWEC filed on behalf of municipal electric departments located in the following Massachusetts cities and towns: Ashburnham, Belmont, Boylston, Braintree, Chicopee, Concord, Danvers, Georgetown, Groton, Hingham, Holden, Holyoke, Hudson, Hull, Ipswich, Littleton, Mansfield, Marblehead, Merrimac, Middleborough, Middleton, North Attleborough, Paxton, Peabody, Princeton, Reading, Rowley, Shrewsbury, South Hadley, Sterling, Templeton, Wakefield, West Boylston, and Westfield (Exh. HO-1, p. 1).

Company's goal "to minimize the power costs of its member systems by making available to them an economic and diversified mix of resources by matching appropriate power supply resources with the load characteristics of individual systems" (Exh. HO-1, pp. I.1, I.4).

MMWEC members are not required to take part in MMWEC projects; participation in any particular MMWEC project is subject to the approval of any individual member. Thus, individual member systems maintain control over their respective power supply programs. MMWEC states that its task is to evaluate options, propose the preferred resources to members, and arrange for their implementation when selected; each individual member decides whether to adopt any particular option as part of its resource mix (Exh. HO-1, p. I.1; Tr. I, pp. 7, 73).

Although individual members maintain discretion over their actual power supply choices, the record in this proceeding is sufficient only to enable the Siting Council to evaluate MMWEC's demand forecast and supply plan for the system as a whole, rather than for each of the 33 towns individually (See section IV, infra).

B. History of the Proceedings

On August 1, 1985, the Company filed the demand portion of its Long-Range Forecast of Electricity Needs and Resources ("1985 Forecast") (Exh. HO-1). On August 19, 1985, MMWEC filed the supply portion of that forecast (Id.). The Company provided notice of the proceeding by publication and posting in accordance with the directions of the Hearing Officer.

On October 8, 1985, the Coalition for Municipal Ratepayers' Rights ("Coalition") filed a petition to intervene. On January 7, 1986, the Coalition withdrew its petition to intervene.

On March 11, 1986, the Hearing Officer conducted a technical conference to discuss certain information requests.

Evidentiary hearings were conducted on January 13 and January 27, 1987. The Company presented two witnesses at the hearings: John J. Boudreau, Manager of Resource Planning, and William H. Dunn, Jr., Manager of the Power Management Division. Both witnesses testified regarding the Company's supply plan. The Hearing Officer entered 133 exhibits in the record (including two late-filed exhibits), largely composed of MMWEC's responses to information and record requests. The Company also entered 6 exhibits in the record.

Pursuant to a briefing schedule established by the Hearing Officer, the Company filed a proposed tentative decision on April 22, 1987.

II. ANALYSIS OF THE DEMAND FORECAST

A. Standard of Review

As part of its statutory 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 determines whether "projections of the demand for electric power...are based on substantially accurate historical information and reasonable statistical projection methods." G.L. c. 164, sec. 69J. To ensure that the foregoing standard is met, the Siting Council applies three criteria to demand forecasts: reviewability, appropriateness, and reliability.

A demand forecast is reviewable if it contains enough information to allow full understanding of the forecasting methodology. A forecast is appropriate if the methodology used to produce that forecast is technically suitable to the size and nature of the utility that produced it. A forecast is reliable if the methodology provides a measure of confidence that its data, assumptions, and judgments produce a forecast of what is most likely to occur. Boston Edison Company, EFSC 85-12 (Phase II), 15 DOMSC 287, 294 (1987).

As the joint-action agency responsible for preparing the demand forecasts for its members, MMWEC argues that it faces special forecasting problems associated with the dispersed and diverse nature of its members' service areas (Exh. HO-MF-2). The Siting Council takes this circumstance into account in its review of MMWEC's forecast.

B. <u>Demand Forecast Results</u>

In the 1985 Forecast, MMWEC projected its total system requirements would grow 2.7 percent annually, on average, over the next decade. MMWEC bases its aggregate demand forecast on the results of town-specific demand projections for MMWEC's 33 members, as shown in Table 1. MMWEC estimated that aggregate sales to industrial customers would increase 4.3 percent per year, a higher rate than its estimated commercial sales, at 3.1 percent annual growth, and residential sales, at 1.2 percent per year. MMWEC projected that its member systems' non-coincident winter and summer peak loads will grow 2.9 percent per year (Exh. HO-1, Table III-1). (See Table 2.)

MMWEC's demand forecast continues to rely upon the same end-use and econometric approaches the Company relied upon in preparing its previous forecast. The residential forecast is based on end-use analysis and the commercial and industrial sales forecasts are developed through econometric equations (Exh. HO-1, Sec. II).

C. <u>Evaluation of the Demand Forecast</u>

Since much of MMWEC's forecasting approach has remained unchanged since the Siting Council conditionally approved that methodology in 1984, the Siting Council focuses its discussion here on: (1) MMWEC's compliance with the three demand-related conditions imposed by the Siting Council in <u>Massachusetts Municipal Wholesale Electric Company</u>, 11 DOMSC 237 (1984); and (2) any significant changes made in MMWEC's methodology, data and assumptions since that decision.

1. <u>Compliance with Previous Demand Forecast Conditions</u>

In its last filing with the Siting Council, MMWEC used a "hybrid" forecast methodology, which replaced the Company's previous survey-interview forecasting technique. MMWEC's previous residential forecast was based on the NEPOOL end-use model; the commercial and industrial forecasts were produced using MMWEC's own econometric models.

In its 1984 decision, the Siting Council approved the changes MMWEC had made in its demand forecasting methodology, but attached conditions to the approval requiring the Company to take steps to improve the data inputs MMWEC used to develop its forecasts. Massachusetts Municipal Wholesale Electric Company, 11 DOMSC 237, 249-250 (1984).

The three conditions the Siting Council imposed on MMWEC regarding its demand forecasting were:

(1) that MMWEC report on its progress in improving the level of disaggregation of its commercial/industrial data base;

(2) that MMWEC conduct a literature search on residential appliance use estimates and discuss the applicability of NEPOOL data for MMWEC's member systems; and

(3) that MMWEC perform a study of the aggregate price elasticity of demand for the residential class of its members.

As discussed in Section II.C.2, infra, MMWEC has complied with these conditions.

2. Methodological/Data Issues

a. Residential Forecast

MMWEC's residential end-use model projects the sector's demand through a set of equations that sums expected energy consumption of all electric appliances and equipment in the homes of customers in members' service areas. Therefore, the forecast relies on estimates of (i) residential customers, (ii) their appliance stock, and (iii) their use of those appliances (Exh. HO-1, p. II.1).

i. Number of Residential Customers

MMWEC projects the number of residential customers (i.e., households) in each town by estimating the town's population and then dividing that estimate by projected average household size (Exh. HO-1, pp. II.3-II.11). MMWEC developed annual population estimates for each town by using population growth-rate forecasts prepared by regional planning commissions[2] ("RPC") to project growth from the 1980 population level found, for each town, in U.S. Census Bureau data (Exh. HO-RSF-3). MMWEC assumed that household size will change at the same annual rate as the national average (projected by the U.S. Census Bureau) and that the relative share of single- and multi-family households in each town is stable (Exh. HO-1, p. II.3-II.6).

Since then, MMWEC has reevaluated its methodology and, in light of its reliance upon updated population data, asserts that the methodology is the best approach available to the Company (Exh. HO-1, pp. II.3-II.11).

The Siting Council finds that the Company's projection of the number of residential customers is an appropriate input to MMWEC's forecast of residential demand.

Accordingly, the Siting Council finds that the Company's projection of number of residential customers is appropriate as an input to MMWEC's forecast of residential demand.

ii. Number of Appliances

MMWEC projects the number of appliances by forecasting appliance saturation rates and then multiplying these estimates by the number of households (Exh. HO-1, pp. II.12-II.19). MMWEC employs different methods for projecting appliance saturation rates for different types of appliances.[3] For example, MMWEC uses regression

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2/The Central Masachusetts Planning Commission ("CMPC") uses Massachusetts Department of Public Health ("MDPH") projections; therefore, MMWEC's population growth rates for towns in central Massachusetts -- Boylston, Holden, Paxton, Princeton, Shrewsbury, Sterling, and West Boylston -- are based on MDPH estimates (Exh. HO-1, p. II.4; Exh. HO-6; Exh. HO-RSF-2).

3/Appliance categories are: income-sensitive appliances; central-space-conditioning and water-heating appliances; technology-constrained appliances; and market-saturated appliances (Exh. HO-1, p. II.12).

analysis to estimate town-specific saturations for income-sensitive appliances.[4] MMWEC clustered towns into five groupings based on median income. Future appliance saturations for any town were then estimated by using Data Resources, Inc.'s projections of each town's average real income for the year 2000. MMWEC compared these projections with the 1984 appliance saturations as estimated by MMWEC's appliance ownership survey to determine the annual increase in appliance ownership for each appliance type for each town grouping (Exh. HO-1, p. 14).

MMWEC's current methodology is based on recent data from the 1984 appliance saturation survey and actual mean income statistics for each town (Exh. HO-RSF-4; Exh. HO-RSF-8). This methodology represents an improvement over the previous filing's reliance upon outdated census information and questionable income distribution assumptions for different MMWEC towns. Accordingly, the Siting Council finds that MMWEC's current methodology for estimating appliance saturation rates is appropriate and reliable.

iii. Appliance Usage

The Siting Council previously criticized MMWEC's approach to estimating average usage per appliance. Specifically, the Siting Council noted that MMWEC's methodology relied upon usage data developed from studies conducted over numerous time periods, geographic locations, and household characteristics. For the most part, the samples described in these studies were unrepresentative of the appliance stock and customers in MMWEC member systems. The Siting Council ordered the Company to: "[c]onduct a literature search on residential appliance use estimates, and either demonstrate the

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4/The following appliances were assumed to be income sensitive: room air conditioners; ranges; standard refrigerators; frost-free refrigerators; standard freezers; frost-free freezers; televisions; dryers; dishwashers; washers (Id.).

applicability and superiority of the NEPOOL data for MMWEC's members in light of the research, or address appropriate changes in the residential data base." Massachusetts Municipal Wholesale Electric Company, 11 DOMSC 237, 283 (1984).

In response, MMWEC provided evidence that it conducted a literature review to collect appliance usage estimates from different sources (Exh. HO-1, App. H-1). Based on its review, MMWEC concluded that: "NEPOOL average [appliance] use data fit well within the range of average usages estimated by other studies" (Exh. HO-1, pp. 13, II.20-II.29; Exh. HO-RSF-9; Exh. RSF-13). Furthermore, MMWEC asserts that "the wide range of estimates that do exist, suggests that it is unlikely there is some other study which can be used which will significantly reduce the need to make the calibrations now being made....some calibration of the forecast result to a base year is standard in any end-use methodology" (Exh. HO-1, p. 14).

MMWEC has established that it has conducted and documented a thorough survey of available literature regarding appliance usage estimates. Accordingly, the Siting Council finds that the Company has complied with Condition 2 regarding appliance usage literature as set forth in the most recent Siting Council order. The Siting Council further finds that the Company's appliance usage estimates are an appropriate input to MMWEC's projections of residential demand.

iv. Price Elasticity

MMWEC states that in response to the Siting Council's condition in its previous order, MMWEC performed an aggregate price elasticity study for its members' residential classes (Id., pp. 16-20). MMWEC structured the study to evaluate kilowatthour demand as a function of income, degree days, distillate fuel price, lagged sales, and electricity price (Id., pp. 17-18). MMWEC asserts that the results of this and other analyses support MMWEC's continued use of NEPOOL price elasticities (Id., pp. 18-20).

The Siting Council finds that MMWEC has complied with Condition 3 as set forth in the previous Siting Council decision.

b. Commercial/Industrial Forecast

MMWEC projects commercial and industrial demand using econometrically derived historical relationships between electricity sales in these sectors and Gross State Product, real electricity prices, and petroleum prices[5] (Exh. HO-1, pp. II.30-II.42; Exh. HO-ISF-2). MMWEC states that it uses pooled time-series and cross-sectional data for groups of towns because of the limited number of observations for individual towns (Exh. HO-1, pp. 10-12, II.31-II.32; Exh. HO-ISF-1). MMWEC stratified towns into three groups for each sector based on the intensity of energy use (i.e., kilowatthour sales per employee) (Id.).

The summary statistics for MMWEC's regression models suggest that the equations provide an adequate fit with historical experience (Exh. HO-1, pp. II.35-II.37; also Exh. HO-ISF-3). Nonetheless, the Siting Council is concerned that classifying towns on the basis of towns' average kilowatthour sales per employee does not ensure reliable forecast estimates. For example, the regression models as specified by MMWEC might not capture any structural changes that may be occuring in some members' commercial and industrial sectors but not in others' that are part of the same cluster of towns based on kilowatthour sales per employee. MMWEC itself conceded that it would prefer to use municipal level data and to explore relying upon data for other variables, such as industrial customers' processes and products -- data which might suggest similarities with respect to capital equipment and the opportunities (both economic and engineering) for substitution among the factors of production (Exh. HO-1, p. II-31). However, MMWEC states that such data are not readily available.

On this issue, the Siting Council previously ordered MMWEC to report on "progress in improving the level of disaggregation of its

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5/MMWEC uses distillate oil price for the commercial sector and residual oil price for the industrial sector (Exh. HO-1, p. 12).

DECISIONS AND ORDERS

MASSACHUSETTS ENERGY

FACILITIES SITING COUNCIL

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commercial/industrial data base. The report should include a description and evaluation of past C/I sales data, a list of alternative improvements, and a description of improvements that have been made to better identify and forecast the components of the C/I load." Massachusetts Municipal Wholesale Electric Company, 11 DOMSC 237, 283 (1984).

In this filing, MMWEC responded that while it recognizes that Siting Council Rule 63.7(2) requires that all electric utilities disaggregate their industrial sales by two-digit SIC codes, the Company asserts that its members have not completed the data-disaggregation effort necessary to comply with that rule (Exh. HO-ISF-9). MMWEC argued that "due to its special circumstances, it may not be feasible in the near future to forecast at such a level of disaggregation. Nevertheless, MMWEC and the EFSC share the objective of obtaining more disaggregated data as a possible means of refining MMWEC's forecasting methodology" (Exh. HO-1, p. 7).

Although MMWEC has "reported" on its progress regarding diaggregation of its commercial/industrial data base, as required by the Siting Council in Condition 1 of its last decision, the Company has made no real progress in this area. Ultimately, these non-town-specific forecasts and the lack of disaggregation in the commercial and industrial sectors undermine the reliability of MMWEC's forecasts for those sectors. Reliable forecast results for individual towns are critical due to the facts that (1)MMWEC's forecasts indicate that the commercial and industrial classes are the fastest growing sectors, and (2) MMWEC and individual member systems must use town-specific forecasts that include projected sales to the commercial/industrial classes as a basis for supply planning and decision making. Accordingly, the Siting Council accepts MMWEC's forecasts for the commercial and industrial sectors as minimally reliable.

While MMWEC states that sufficient data are not available at present to forecast commercial/industrial sales in each town at the two-digit SIC-code level, the Siting Council questions MMWEC's response to these data limitations. Rather than pursue collection of such critical data for all member systems, as required by Siting

Council regulations and as necessary for refinement of the Company's commercial and industrial demand forecasting methodologies, MMWEC has continued to adapt its method to accommodate data limitations. As a result, the Company continues to forecast sales for clusters of towns in a manner that does not directly capture different industries' energy intensities or their differential responsiveness to price.

The Siting Council notes that MMWEC's service territory is both economically diverse and geographically dispersed. For these reasons, MMWEC must remedy the problems in its commercial/industrial databases that create the need for MMWEC to forecast demand in those sectors at such a non-disaggregated level. The Siting Council hereby orders MMWEC and its members to disaggregate their industrial databases in compliance with Siting Council Rule 63.7(2) and their commercial databases in a manner that captures electricity-consumption differences among various categories of commercial establishments. Additionally, the Siting Council orders MMWEC to develop forecasting methodologies for the commercial and industrial sectors that rely upon these new disaggregated databases.

Finally, the Siting Council notes that MMWEC may not have sufficient time to collect the required disaggregated data in time for presentation and use in its next filing. Therefore, the Siting Council orders MMWEC to comply with this condition in the Company's first forecast filing that occurs after twelve months from the date of this decision.

3. Conclusions

In regard to the Company's residential demand forecast, the Siting Council has found that MMWEC has complied with Conditions 2 and 3 from the previous order. The Siting Council also has found that the Company's projections of the number of residential customers is an appropriate input to MMWEC's residential demand forecast. Accordingly, the Siting Council finds that the Company's residential demand forecast is reliable.

In regard to the Company's commercial and industrial demand forecasts, the Siting Council has found that MMWEC has minimally complied with Condition 1 that required the Company to report on its progress in disaggregating its commercial/industrial databases. Further, the Siting Council has found that MMWEC's forecasts for the commercial and industrial sectors are minimally reliable.

Finally, the Siting Council has ordered MMWEC and its members to disaggregate their industrial databases in compliance with the Siting Council's Rule 63.7(2) and their commercial databases in a manner that captures electricity-consumption differences among various categories of commercial and industrial sectors that relies upon these disaggregated databases. The Siting Council has ordered MMWEC to comply with these requirements in the Company's first forecast filing that occurs after twelve months from the date of this decision.

For the foregoing reasons, the Siting Council hereby approves the Company's demand forecast.

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 reviews three dimensions of an electric utility's supply plan: adequacy, diversity, and cost.

The adequacy of supply is a utility's ability to provide sufficient capacity to meet its peak loads and reserve requirements throughout the forecast period. Cambridge Electric Light Company, 12 DOMSC 39, 72 (1985); Boston Edison Company, 10 DOMSC 203, 245 (1984). The diversity of supply measures the relative mixture of supply sources and facility types. The Siting Council's working principle is that a more diverse supply mix, like a diversified financial portfolio, offers lower risks. Boston Edison Company, EFSC 85-12 (Phase II), 15 DOMSC 287, 350 (1987). The Siting Council also evaluates whether a supply plan minimizes the cost of power subject to trade-offs with adequacy, diversity, and the environmental impacts of construction and operation of new facilities. Nantucket Electric Company, EFSC 86-28, 15 DOMSC 363, 384-390 (1987). The Siting Council's evaluation of the long-run cost of the supply plan generally focuses on a company's supply planning methodology. Boston Edison Company, EFSC 85-12 (Phase II), 15 DOMSC 287, 339-349 (1987); Cambridge Electric Light Company, EFSC 86-4, 15 DOMSC 125, 136-138, 165-166 (1986). Finally, the Siting Council determines whether utilities treat all resources -- including demand management, conventional power plants, and purchases from cogeneration and small power projects and from other utility and non-utility suppliers -- on the same basis when attempting to develop an adequate, diverse and least-cost supply plan.[6] Boston Edison Company, EFSC 85-12 (Phase

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6/In 1986, the Massachusetts legislature amended the Siting Council's statute to require the [footnote continued on next page]

II), 15 DOMSC 287, 315-323 (1987); Cambridge Electric Light Company, EFSC 86-4, 15 DOMSC 125, 133-135, 151-155, 166 (1986).

Further, the Siting Council reviews the supply planning processes utilized by utilities. Recognizing that supply planning is a dynamic process undertaken under evolving circumstances, the Siting Council requires utilities' to identify, evaluate, and choose from a variety of supply options based on reasonable, appropriate, and documented criteria. A company's consistent and systematic application of such criteria to supply planning decisions indicates that a company is evaluating new supply options in a manner that ensures an adequate supply of least-cost, least-environmental-impact power. These processes and criteria take on added importance when the dynamic nature of the energy generation market and the inherent uncertainty of projections make it difficult for a company to identify with exactitude all the power resources it plans to rely upon in the latter years of its long-range forecast. Nantucket Electric Company, EFSC 86-28, 15 DOMSC 363, 378-379, 384, 390-391 (1987); Boston Edison Company, EFSC 85-12 (Phase II), 15 DOMSC 287, 301, 322-323, 339-348 (1987); Cambridge Electric Light Company, EFSC 86-4, 15 DOMSC 125, 133-135 (1986); Fitchburg Gas and Electric Light Company, 13 DOMSC 85, 102 (1985).

The Siting Council has determined that different standards of review are appropriate and necessary to establish supply adequacy in the short run and the long run. Cambridge Electric Light Company, EFSC 86-4, 15 DOMSC 125, 134 (1986).

To establish adequacy in the short run, a company must demonstrate that it has an identified, secure, and reliable set of energy and power supplies. In essence, the company must own or have under contract sufficient resources to meet its capability

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[footnote continued from previous page] Siting Council to approve a company's 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.

responsibility under a reasonable range of contingencies. If a company cannot establish that it has adequate supplies in the short run, that company must then demonstrate that it operates pursuant to a specific action plan guiding it in being able to rely upon alternative supplies should necessary projects not develop as originally planned. Boston Edison Company, EFSC 85-12 (Phase 2), 15 DOMSC 287, 309-322 (1987); Cambridge Electric Light Company, EFSC 86-4, 15 DOMSC 125, 134-135, 144-150, 165-166 (1986). The Siting Council has defined the short run as the period of time necessary to place into service sufficient resources obtainable from the shortest-lead-time resource option under a given company's control in a timely and cost-effective manner. The short run may vary on a company-by-company basis. Boston Edison Company, EFSC 85-12 (Phase 2), 15 DOMSC 287, 297, 307-308.

To establish adequacy in the long run, a company must demonstrate that its planning processes can identify and fully evaluate a reasonable range of supply options on a continuing basis while allowing sufficient time for the company to make appropriate supply decisions to ensure adequate, cost-effective energy and power resources over all forecast years. The Siting Council recognizes that the later years of the forecast may offer new, but as yet unknown, resource options which are both reliable and cost-effective. The potential for these new resource options should increase in an electric generation and transmission market that adapts to a higher degree of uncertainty, becomes more competitive, and spawns projects which have shorter lead times. In formulating its standard for adequacy in the long run, the Siting Council recognizes this new energy environment and affords companies the opportunity to plan for their supplies in a creative and dynamic manner. Id., pp. 298, 313-320.

B. Previous Supply Plan Reviews

In its 1984 order, the Siting Council raised concerns regarding the adequacy of MMWEC supply plans for certain member systems. MMWEC's forecasts and plans for five towns -- Hudson, Littleton, Princeton, Shrewsbury, and Templeton -- indicated that those towns would experience deficiencies[7] by 1986/87. Massachusetts Municipal Wholesale Electric Company, 11 DOMSC 237, 269-270 (1984). The Siting Council directed MMWEC to file a supply plan indicating how MMWEC intends to ensure a reliable supply of electricity for each of its member systems. Id., p. 271.

In Condition 4 of its decision, the Siting Council further ordered MMWEC to "provide in its next forecast Supplement a comprehensive and aggressive plan to implement demand reduction programs and identify potential alternative sources of generation, including coal, cogeneration, imported power, renewables and other sources for the forecast period." Id., p. 284.

The Siting Council's evaluation of the Company's compliance with this filing requirement and with Condition 4 is contained in sections III.D.1.c.iii, III.D.1.e.ii, III.D.2, and III.F, infra.

C. Supply Planning Process - Overview

MMWEC has described its members' supply resources as including: generating units built and operated by MMWEC for its members; MMWEC's joint ownership shares in generating units built by private utilities (e.g., Seabrook 1); power purchase contracts; local systems' generating units; members' direct ownership in regional generating projects; imported power; purchases from small power and cogeneration facilities; and conservation and load management (Exh. HO-1, pp. I.1-I.2).

In the current Forecast, MMWEC did not present a supply plan that specifically identified how all member systems would meet their projected customers' load and reserve requirements throughout the forecast period. Instead, MMWEC identified and analyzed specific resource options, performed certain contingency analyses, and

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7/The Siting Council defines a deficiency as a situation where a company's or municipal light department's available resources are less than its capability responsibility -- the sum of its peak load and reserve requirements.

explained its planning process for analyzing supply options generally (Exh. HO-AS-1).

MMWEC described its supply planning process as follows: MMWEC identifies supply options from various sources of information. MMWEC's Power Resource Development Committee, comprised of representatives of member systems, reviews these options in order to recommend the ones most appropriate for further development as long-term supply options. MMWEC states that following more detailed reviews of system needs and specific supply options, MMWEC's staff prepares system-specific analyses relating to an identified supply option for each individual member, which in turn reviews and considers whether to participate in it (Exh. HO-TSPP-4; Exh. HO-10; Exh. HO-15; Exh. HO-TSPP-1). MMWEC further asserts that this procedure, along with the work of another new member committee -- the Load Management and Conservation Committee -- helps to ensure that MMWEC has identified the "most cost-effective supply resources and the cost-effective maximum achieveable conservation potential" (Tr. I, p. 51).

MMWEC's supply planning process involves two different types of methodologies, each aimed at developing a mix of resource options for member systems within a different time frame. For long-run supply planning, MMWEC utilizes a generation expansion planning approach, aided by the Automatic Generation Planning Model ("AGPM"), to identify the optimal or least cost option(s) to pursue among a set of generic and specific resource options (Exh. HO-8; Exh. HO-TSPP-1). For short-run planning, MMWEC uses a different supply planning approach -- one the Company calls the "Extended Weekly Studies Program" ("EWSP") -- to evaluate the adequacy of individual members' resources and to analyze ways to modify or "fine tune" members' supplies to minimize costs while maintaining sufficient capacity to meet load and reserve requirements (Exh. HO-AS-2; Exh. HO-9; Exh. HO-AS-7).

To evaluate MMWEC's supply plan and the Company's reliance upon AGPM and EWSP as part of a supply planning process that ensures an adequate supply of energy at minimum cost, the Siting Council reviews them in the context of the Siting Council's short-run and long-run adequacy standards (see section III.D.1 and III.D.2, infra) and cost standard (see section III.E, infra).

D. Adequacy of the Supply Plan

In accordance with the Siting Council's previously articulated standard of review, Section III.A., supra, MMWEC's supply plan is evaluated in terms of its ability to meet resource requirements in both the short run and the long run.

1. Adequacy of Supply in the Short Run

a. Definition of the Short Run

A company's short-run planning period is defined as the time required for a company to place into service resources under its direct control in sufficient quantities to meet the projected need for new capacity. The short-run planning period varies on a company-by-company basis. MMWEC asserts that its shortest-lead-time resource would be peaking capacity (i.e., a gas turbine or a series of diesel units), requiring a 4.5-year lead time to place into service (Tr. II, pp. 21-24; Exh. HO-16). Accordingly, the Siting Council finds that MMWEC's short-run period would be four years, through power year 1990/91.

b. Base Case Supply Plan

MMWEC estimates that if its members' combined peakload and reserve requirements together grow at 3.4 per cent per year over the forecast period,[8] then MMWEC members, in aggregate, will experience

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8/As of its most recent forecast (prepared in January 1986), MMWEC estimates that its peak loads will grow 3.0 per cent per year from 1986/87 through 1993/94 (Exh. HO-AS-6; Exh. HO-AS-12; Exh. JJB-1). (This 1986 forecast projects [footnote continued on next page] a capacity deficiency starting in the 1989/90 power year[9] unless members obtain an additional 8 MW of capacity that is, as-yet, uncommitted. (See Table 3.) By the end of the short-run planning period in 1990/91, MMWEC expects that its member systems will need to add 27 MW of capacity (Exh. JJB-1; Exh. HO-AS-6). These estimated capacity deficiencies are the result of the Company's updated base-case forecast and supply plan, which includes planned capacity additions associated with Seabrook 1, Cleary 9, and Hydro Quebec Phase 2 (See Table 3).

MMWEC did not specifically identify the resources its members will rely upon to meet their requirements throughout the forecast period (Exh. HO-1, pp. I.6-I.12; Exh. HO-AS-6; Exh. JJB-1). MMWEC instead stated that it "is investigating a variety of power supply and demand side options to meet the projected capacity deficiencies of its

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[footnote continued from preceding page] slightly higher growth than was forecast by MMWEC in 1985 [Exh. HO-1]. See Tables 1 and 2, infra.) But, in that MMWEC also expects its reserve requirement will rise even faster, MMWEC forecasts its capability responsibility to increase 3.4 per cent per year (Exh. JJB-1). In the January 1986 forecast, MMWEC relied upon the same forecasting methodology as the one used in the August 1985 filing (reviewed supra, in Section II), but used different data and assumptions, including 1985 actual energy sales, a newer forecast of economic growth and fuel prices prepared in Fall 1985 by Data Resources, Inc., and updated spot load additions (Exh. HO-AS-12; Exh. HO-17; Tr. I, p. 132). Although the Siting Council has reviewed MMWEC's 1985 Forecast in this decision, the Siting Council utilizes MMWEC's January 1986 demand forecast in evaluating the adequacy of MMWEC's supply plan in the short run, since the 1986 forecast reflects more recent data and assumptions. This is consistent with the Siting Council's consideration of a more recent demand forecast as the basis for determining short-run adequacy in Boston Edison Company, EFSC 85-12 (Phase II), 15 DOMSC 287, 294 (1987).

9/This date is based upon the sum of MMWEC members' combined resources and requirements. Even though capability responsibilities are evaluated on a community-by-community basis by NEPOOL (Exh. HO-NRR-3; Exh. HO-NRR-7), MMWEC asserts that the adequacy of an individual community's resources should be evaluated in the context of MMWEC's total system-wide situation (Tr. 1, p. 97). In this decision, the Siting Council focuses its adequacy review on MMWEC as a whole, although the Siting Council addresses certain supply-planning issues, where appropriate, at the community-specific level.

member systems" (Exh. HO-AS-1).

However, MMWEC identified five resource options which members could decide to use to meet their short-run capacity deficiencies under either base case assumptions or any of the range of contingencies MMWEC has considered (Exh. JJB-3). These resource options specifically include: Pt. Lepreau 1 contract extension; contract demand service extensions; standard offer contracts with small power producers and cogenerators; load management programs; and conservation programs. MMWEC states that if the Company pursued any of these options on behalf of its members, it would not need to undertake new financings to do so (Tr. II, p. 60). Even so, the final choice to pursue any specific options belongs to individual members. MMWEC has presented no construction plans of its own.

c. Short-Run Options

i. Pt. Lepreau 1 Contract

On behalf of its members, MMWEC currently purchases 100 MW of capacity from New Brunswick Power's Pt. Lepreau Unit 1 nuclear facility through a power purchase agreement which expires on October 31, 1988 (Exh. HO-1, App. I-1). This agreement affords MMWEC's members the option to decide as late as seven months prior to contract termination on whether to extend the contract. Should any member choose to extend it, it will be renewable on a yearly basis for up to three years, through October 31, 1991 (Exh. HO-CSS-1; Exh. HO-CSS-12; Exh. HO-11; Tr. I, pp. 56-57).[10]

The MMWEC members which are parties to this contract have not made any final decisions regarding an extension (Exh. HO-CSS-12).

10/Twenty-eight MMWEC members are parties to the MMWEC contract with New Brunswick for Pt. Lepreau power (Exh. HO-CSS-1). MMWEC members which are parties to the contract are free to reduce their portion of MMWEC's total 100 MW in the extension period, although once the contract level is reduced, it cannot be increased within this contract period (Tr. I, p. 60).

MMWEC indicated that the Pt. Lepreau contract would be extended only if it "were the least-cost method of meeting the deficiencies" (Tr. 1, p. 58). MMWEC assumes that some members will not renew the contract given transmission constraints which could adversely affect the contract's economics and given lower oil prices which reduce the attractiveness of non-fossil options (Exh. HO-CSS-1; Exh. HO-CSS-12; Exh. HO-CSS-13). Nonetheless, MMWEC sees Pt. Lepreau as a resource that its members could use to help avoid capacity deficiencies under either base case conditions or in response to contingencies (Tr. I, pp. 57-58).

MMWEC asserts that extension of the contract is contingent upon MMWEC securing satisfactory transmission arrangements (Tr. I, pp. 59, 61-63; Exh. HO-CSS-1). MMWEC's existing contract for the transmission of Pt. Lepreau power runs through the 1989/90 power year. Consequently, if MMWEC were able to extend its Pt. Lepreau power contract through power year 1990/91, MMWEC would need a new transmission contract for the final year of the extension period (Tr. I, pp. 62, 64). Furthermore, MMWEC is concerned that even in the first two years of the extension period, two other transmission-related factors would adversely affect the costs of Pt. Lepreau power: (1) constraints that exist at certain times on the ability of the northern New England transmission system to transfer all available power to southern New England; and (2) certain "hold-harmless" provisions in the transmission contract that require MMWEC to compensate the companies that wheel the power to MMWEC for any costs that could result when transfer constraints on these lines would require these companies to back down any of their own economic resources and replace them with more costly power (Exh. HO-CSS-13).

Based on MMWEC's assertions that (1) a two-year extension of the Pt. Lepreau contract is available and depends on the relative economics of the power at that time, and (2) existing transmission capacity would enable MMWEC to count the Pt. Lepreau contract towards MMWEC members' capability responsibilities, the Siting Council finds that MMWEC can reasonably expect to rely upon 100 MW from Pt. Lepreau Unit 1 to meet its capability responsibilities in both the 1988/89 and 1989/90 power years.

Recognizing, however, that MMWEC has not (1) taken steps to secure all firm transmission contracts needed for the third year of the Pt. Lepreau contract extension period, and (2) provided assurances that it will be able to secure such new transmission contracts, the Siting Council finds that MMWEC cannot rely for planning purposes upon 100 MW from Pt. Lepreau in 1990/91, the third year of the Pt. Lepreau contract extension period. Accordingly, the Siting Council finds that MMWEC cannot rely for planning purposes upon an extension of the Pt. Lepreau contract to meet its short-run adequacy requirements.

ii. Contract Demand Service Agreements

MMWEC states that several of its members may extend the contract demand services[11] now provided to them by Boston Edison Company and
Northeast Utilities (Tr. I, pp. 64-65). These contracts allow Northeast Utilities and Boston Edison Company to notify MMWEC at any time that the contract will not be extended starting four or five years from the date of notice (Tr. I, pp. 65-67; Exh. HO-19, p. 2; Exh. HO-22). Therefore, given the four-to-five year notice requirements for contract termination, the Siting Council finds that MMWEC can reasonably rely upon the availability of these resources to meet two members' capability responsibilities in the short run.

11/Under contract demand service agreements, the utility providing service -- rather than the utility buying the service -- is required to meet the reserve requirements on the demand level provided for under the agreement. MMWEC's agreements allow for the following extensions: Westfield's 2 MW from Northeast Utilities; Chicopee's 20 MW from Northeast Utilites; South Hadley's 1 MW from Northeast Utilities; and Reading's 38 MW from Boston Edison Company (Tr. II, pp. 34-39; Exh. HO-NRR-1; Exh. HO-NRR-4; Exh. JJB-3). For 1990/91, these extensions amount to 61 MW, which is equivalent to a 70 MW contribution toward's MMWEC's ability to meet its capability responsibility (due to the effective 14-percent reserve carried for these agreements by the utility providing the service to MMWEC members). (Tr. II, p. 37; Exh. HO-NRR-1; Exh. HO-NRR-4).

Accordingly, the Siting Council finds that MMWEC can rely for planning purposes upon the extension of contract demand service agreements to meet its short-run adequacy requirements.

iii. Standard Offer Contract

MMWEC also states that it can meet identified capacity shortfalls through contracts with certain small power producers and cogenerators (known as "Qualifying Facilities," or "QFs") (Exh. JJB-3).

MMWEC recently instituted a standard offer contract for QFs that are small (between 0.1 MW and 2 MW) and medium sized (between 2 and 10 MW).[12] Twenty-two MMWEC members are participating in this standard offer contract to obtain 16.4 MW of QF capacity starting in November 1989 (Exh. HO-SPP-1; Tr. I, p. 66; Exh. HO-CSS-4). Under the contract, QFs will be paid "the weighted average of Purchaser's [i.e., the participating MMWEC member] avoided cost, with the weights being each Purchaser's share of the standard offer total" (Exh. HO-SPP-1, Att. 2, p. 23). QFs may receive these energy and capacity payments in a front-end loaded fashion through levelized pricing schedules (Exh. HO-SPP-2). Furthermore, MMWEC can terminate the agreement if: (1) MMWEC has not received energy from the project by November 1989; or (2) the developer fails to complete specific tasks outlined in the "timeline" of the project (Exh. HO-SPP-1, Att. 2, pp. 11-12; Tr. I, p. 71; Exh. HO-12).

Three developers representing four QF projects amounting to 16.4 MW of capacity available to MMWEC members[13] have signed

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12/MMWEC has determined that "larger projects [greater than 10 MW] are important enough to warrant a specific analysis" (Exh. HO-SPP-1, Att. 2, p. 23).

13/MMWEC has contracted for only a part of the total capacity from these four projects: (1) Viking Energy Corporation's 5 MW wood plant in Ayer, scheduled for December 1989; (2) Viking Energy Corporation's 7.5 MW wood plant in Adams, scheduled for December 1989; (3) Little Power Company's 1 MW hydro plant in Westfield, scheduled for December 1987; and (4) Enertrac's 10.5 MW combined cycle project in Peabody, scheduled for April 1987 (Exh. HO-12; Tr. I, p. 68).

agreements with MMWEC (Tr. I, p. 67). For the signed agreements to take effect, however, these developers must still agree to the security requirements approved by the MMWEC Board of Directors (Tr. I, pp. 67-69; Exh. HO-SPP-1, Att. 2, p. 11). MMWEC asserts, therefore, that these projects remain somewhat uncertain.

MMWEC was the first utility in Massachusetts to issue a standard offer contract with payments based on avoided costs. Based upon that fact, along with the agreements MMWEC members have signed with QF developers, the Siting Council finds that MMWEC has satisfactorily complied with that portion of Condition 4 from the previous order requiring MMWEC to file a plan to identify potential resources from renewable energy and cogeneration projects.

Further, based upon the evidence provided by MMWEC that the signed QF projects are proceding on schedule, the Siting Council finds that MMWEC can rely for planning purposes on the capacity associated with these QF projects starting in 1989/90 to meet the Company's short-run adequacy requirements.[14]

iv. Load Management

MMWEC asserts that its members could control presently uncontrolled electric hot water heaters to realize a 7 MW peakload reduction by 1988/89 and a 15 MW reduction beginning in 1989/90. MMWEC estimates that such a load-management program has a one-year lead time (Tr. I, p. 79). MMWEC asserts that decisions and actions related to implementing this proposed program rest with individual members (Tr. I, p. 73). Furthermore, the program is still under review and as yet no towns have allocated resources to it.

In order for this load management option to be effective in

14/This analysis is consistent with the manner in which the Siting Council evaluated the ability of another company to meet its short-run adequacy requirements through a planned supply mix that counted the yet unlicensed or unconstructed small-power/cogeneration projects as part of the Company's total base-case capacity. Boston Edison Company, EFSC 85-12 (Phase II), 15 DOMSC 287, 306-308, 314-315 (1987).

actually reducing MMWEC members' peak demand in the short run, the Siting Council recognizes that MMWEC must take whatever steps are necessary to help insure members' implementation of the controlled water heater program. Still, given the short lead time for program implementation, the well-established nature of such a program, and the small peakload targets MMWEC has set for it, the Siting Council finds that this is a viable strategy. Accordingly, the Siting Council finds that MMWEC can rely for planning purposes upon the capacity associated with its load management program to meet its short-run adequacy requirements.

v. Conservation

MMWEC also projects that conservation programs could reduce load by 7 MW per year beginning in 1987/88 (Exh. JJB-3). By 1991/92, MMWEC believes its members' aggregate peak could be reduced by 35 MW through conservation (Exh. HO-JJB-3). The four programs identified by MMWEC -- residential weatherization, commercial lighting, municipal street lighting, and commercial and industrial demand services -- are being implemented on a test basis by a number of MMWEC members (Tr. I, pp. 67-78).

Given the short lead time for implementing these programs and the fact that MMWEC communities have already started to implement them (Tr. I, p. 78), the Siting Council finds that MMWEC can assume for planning purposes that its members will achieve the targeted energy and load reductions attributable to these conservation programs. Accordingly, the Siting Council finds that MMWEC can rely for planning purposes upon capacity associated with its planned conservation programs to meet its short-run adequacy requirements.

d. Adequacy of the Base Case with Short-Run Options

MMWEC's base case supply plan indicates that the Company expects that without the addition of new resources, its member systems together will experience short-run deficiencies of 8 MW starting in

1988/89 and higher deficiencies thereafter (See Table 3).

Of the resource options identified by MMWEC to meet the members' capability responsibilities and thereby avoid base-case shortfalls in the short run, the Siting Council finds that all but one -- the third year of the Pt. Lepreau 1 contract extension -- can be relied upon by MMWEC for the purpose of satisfying the Siting Council's short-run adequacy standard. With these resource additions, MMWEC would have sufficient resources to meet its members' projected requirements through the short-run period, or power year 1990/91, assuming no contingencies (See Table 3). Therefore, the Siting Council finds that MMWEC has sufficient options to meet its base-case deficiencies in the short run.

e. Short-Run Contingency Analysis

In order to establish adequacy in the short run, a company must also establish that it can meet its forecasted needs under a reasonable range of contingencies. To evaluate the adequacy of MMWEC's short-run supply plan, the Siting Council analyzes two contingencies: (i) simultaneous delay of the small power projects associated with MMWEC's standard offer contract; and (ii) loss of Seabrook 1.[15]

i. Delay of Small Power Projects

The Siting Council evaluates the adequacy of MMWEC's short-run supply plan if there is a one-year delay in the availability of power to be produced by the four new small power projects signed up by MMWEC

15/ MMWEC also examined its additional supply needs in the event that the Hydro Quebec Phase II contract were delayed. Since this contingency falls outside of the short run, the Siting Council does not evaluate this contingency here. See Section III.D.2, *infra*.

through its first standard offer contract offering.[16] MMWEC expects these facilities to deliver 16 MW of power starting in power year 1988/89 (See Section III.D.1.c.iii, supra).

If all other resources in its base-case supply plan were available to MMWEC, along with the other options the Siting Council has found to be reliable for planning purposes[17] (See Section III.D.1.d, supra), a one-year delay in these small power projects would not cause a short-run deficiency in MMWEC's system supply plan (See Table 5).

Accordingly, the Siting Council finds that the Company has established that it has adequate supplies to meet requirements in the short run in the event of simultaneous one-year delays of the four planned small power projects.

ii. Delay or Cancellation of Seabrook 1

MMWEC, on behalf of 28 of its members, is a joint participant in the Seabrook nuclear project. MMWEC members' 10.4-percent share[18] of Seabrook 1 entitles them to 119.5 MW of the plant's 1150 MW of capacity (Exh. HO-1, App. I-1).

In this proceeding, MMWEC presented an evaluation of the adequacy of its resources in the short run under the contingency that Seabrook 1, the one resource in its base-case supply plan that is not

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16/This is consistent with the manner in which the Siting Council evaluated the ability of another company to meet its capability responsibility in the event that planned but not yet licensed or contructed small power or cogeneration projects were delayed. Boston Edison Company, EFSC 85-12 (Phase II), 15 DOMSC 287, 315-316 (1987).

17/Specifically, these include: a two-year extension of the Pt. Lepreau contract; an extension of contract-demand services; the four small power projects signed through the standard offer contract; load management; and conservation (See Section III.D.1.d, supra).

18/MMWEC also owns a 1.2-percent share of Seabrook on behalf of other utilities that are not members of MMWEC (Tr. 1, p. 92).

yet in service, were unavailable (Exh. JJB-2; Exh. JJB-3).

Although Seabrook 1 was scheduled to begin commercial operation in 1986, it was not in service as of the time of hearings in this proceeding. MMWEC states that there is "uncertainty as to the date that it [will]...enter commercial operation" and that the resolution of the licensing uncertainties is beyond MMWEC's control (Tr. 1, p. 90)[19] Therefore, MMWEC notes that it considers the cancellation of Seabrook as a contingency for which the Company must plan (Exh. JJB-2).

MMWEC has signed an agreement with Public Service Company of New Hampshire ("PSNH") which requires PSNH to repurchase up to 50 MW of Seabrook 1 capacity and energy for three years following commercial operation of the unit and up to 29 MW for an additional seven years (Exh. HO-CSS-6). MMWEC expects that each member eligible to exercise this "buy-back" agreement will elect to do so (Id.). Consequently, for MMWEC's contingency planning purposes, if Seabrook 1 is not available as MMWEC assumes on October 31, 1987, MMWEC will have to replace only the capacity its members would not have sold back to PSNH: 80 MW from 1987/88 through 1989/90, 97 MW through 1996/97, and 120 MW thereafter (Exh. JJB-1; Tr. I, pp. 86-87).

MMWEC has analyzed the adequacy of its members' collective resources if Seabrook 1 is not available throughout the short run. In this case, MMWEC would need to add new resources to avoid a 66 MW shortfall in 1988/89 (See Table 5). In 1990/91, the end of MMWEC's short-run planning period, the Company would have to eliminate a 124 MW shortfall (Exh. JJB-2).

In the event that Seabrook 1 is unavailable, MMWEC indicated that it would pursue the short-run options it calls "contingency resources" (Exh. JJB-3; See Section III.D.1.c, supra). MMWEC asserts

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19/The Nuclear Regulatory Commission has issued a 40-year restricted operating license which allows the plant's operator, New Hampshire Yankee, to load fuel and conduct zero-power testing. Before Seabrook 1 can actually begin commercial operation, New Hampshire Yankee must satisfy a condition which requires that the plant's emergency evacuation plan be approved by the Federal Emergency Management Agency (Tr. I, pp. 89-90).

that there is a "fairly high degree of likelihood that they [these short-run options] would be available to meet these deficiencies" (Tr. I, p. 93). As shown in Table 5, if MMWEC successfully pursued all of the short-run options which the Siting Council has found to be reliable for planning purposes (See Section III.D.1.c and III.D.1.d, supra), the loss of Seabrook would not cause a deficiency in MMWEC's system supply plan in the short run (see Table 5).

Even though the MMWEC system as a whole would not be deficient in the short run if Seabrook 1 is unavailable, many individual MMWEC members would have deficiencies throughout the short run (See Table 6). Therefore, MMWEC has failed to comply with the directive in the Siting Council's previous decision that required MMWEC to provide a supply plan indicating how it will ensure a reliable supply of electricity for each of its member systems. Massachusetts Municipal Wholesale Electric Company, 11 DOMSC 237, 271 (1984).

2. Adequacy of Supply in the Long Run

MMWEC's long-run planning period is the remaining forecast horizon beyond the short run -- from 1991/92 through 1993/94. The Company's most recent forecast and base-case supply plan indicate that during this period, MMWEC members will need to add resources in order to avoid deficiencies amounting to 60 MW in 1991/92 and increasing to 185 MW by 1993/94 (Exh. JJB-1, p. 2) (See Table 3).

In addition to the resource options identified by MMWEC as available to members in the short run (See Section III.D.1.c, supra), the Company indicates that it plans to obtain additional resources in the long run through its members' participation in the Hydro Quebec Phase 2 project.[20] Through a 2000 MW interconnection between NEPOOL and Hydro Quebec's hydroelectric facilities near James Bay, Canada, and under the terms of the Phase 2 Firm Energy Contract, NEPOOL expects to import seven billion kilowatt hours per year from Hydro

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20/The Company's filing also indicates that MMWEC is considering but not yet planning the conversion of certain peaking units to enable them to operate as intermediate units (Exh. CSS-14).

Quebec for ten years starting in power year 1990/91. MMWEC's share of this project represents a capacity value of 56 MW for MMWEC members (Exh. HO-AS-6; Exh. HO-CSS-9; Exh. HO-CSS-10; Exh. JJB-1).

Based on MMWEC's base-case supply plans, including the addition of Hydro Quebec Phase 2, the Company projects deficiencies in every year of the long run.

As previously discussed in Section III.A, supra, the Siting Council does not require an electric company to establish that it has adequate supplies in the long run, as long as the company demonstrates that its planning process can identify and fully evaluate a reasonable range of supply options. The ability of MMWEC's supply planning process to identify and fully evaluate a reasonable range of supply options is fully discussed from the perspective of least-cost supply planning in Section III.E., infra.

As indicated in Section III.E., infra, MMWEC fails to establish that its supply planning process identifies and fully evaluates a reasonable range of supply options. Accordingly, the Siting Council finds that MMWEC's supply plan fails to ensure an adequate supply of resources for its members' customers in the long run.

3. Conclusions on the Adequacy of Supply

The Siting Council finds that MMWEC's supply plan ensures adequate resources to meet the projected aggregate needs of its members' customers in the short run under a reasonable range of contingencies.

At the same time, however, the Siting Council finds that MMWEC has failed to comply with a requirement in the previous Siting Council decision that ordered MMWEC to provide a plan indicating how it will ensure needs of each of its member systems.

Finally, in that MMWEC has failed to establish that its supply planning process fully identifies and evaluates a reasonable range of supply options, the Siting Council finds that MMWEC's supply plan fails to ensure adequate resources to meet the projected aggregate needs of its members' customers in the long run.

E. Least-Cost Supply

1. MMWEC's "Least-Cost Planning" Process

MMWEC's combined short-run and long-run planning processes involve various types of analytic techniques and systems of review that identify and evaluate the costs of resource options available to members in determining their specific long-range supply plans.

a. Short-Run Cost Analyses

MMWEC asserts that in terms of short-run planning, the Company's Extended Weekly Studies Program identifies least-cost supplies and makes them available to members (Exh. HO-AS-3; Exh. HO-AS-7; Exh. HO-9). MMWEC says it uses the program "to estimate the optimum amount of capacity and energy needed that produces the minimum ownload production cost for each MMWEC member system" (Exh. HO-AS-7; Tr. I, pp. 9-17; Exh. HO-AS-14). MMWEC says it developed and implemented this program to prevent capability responsibility deficiencies from occuring and to ensure that members have the "most economical mix of generating resources" at any point in time (Exh. HO-AS-1; Tr. I, pp. 15-16).

MMWEC states it uses the program on a weekly basis to "fine tune" members' generating mixes based on the most current information available on planned and unplanned unit outages, changes in short-term load forecasts, fuel availability, and the availability of short-term contracts to buy and/or sell energy and capability (Exh. HO-AS-14; Exh. HO-AS-7; Tr. I, pp. 9-17).

MMWEC described the operation of the Extended Weekly Studies Program in the following way: To ensure that each member has sufficient capacity to meet its capability responsibility over a capability planning period, MMWEC establishes a minimum capacity surplus for each member (Exh. HO-NRR-3; Tr. I, pp. 21, 23-24, 29). Then, if additional resources are needed, MMWEC arranges for purchases of power from existing power plants "[a]t the start of each capability period...to ensure that each system has enough capacity in its resource mix to exceed its projected capability responsibility by at least the minimum surplus amount" (Exh. HO-NRR-3; Tr. I, p. 20). On a monthly basis, MMWEC reviews the capability responsibility projections made at the beginning of the capability period in light of the actual peak load from the previous month (Exh. HO-NRR-3; Exh. HO-AS-14; Tr. I, pp. 14-15).

To indicate the success of the program, MMWEC provided evidence of the reduced number of capability responsibility deficiency charges incurred by MMWEC members since the Extended Weekly Studies Program was implemented in November 1984.[20A] Only one deficiency charge has been levied against an MMWEC member since the program was introduced, and MMWEC asserts that this was because of a contract reporting error.[21] MMWEC also documented cumulative net savings to members from the program as totalling $8 million since the program began in 1981 (Exh. WHD-1).

b. Long-Run Cost Analyses

i. Capacity Expansion Program Costs

For long-run supply-side cost analyses, MMWEC utilizes a two-stage capacity expansion planning process that MMWEC believes ensures its members a least cost mix of resources. In the first stage, alternatives are compared directly to each other through an initial screening analysis to determine the most likely set of economic resources (Exh. HO-TSPP-2; Exh. HO-TSPP-1). In this initial

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20A/Capability responsibility adjustment charges are assessed to a NEPOOL member whenever that member's capability responsibility exceeds its available resources.

21/MMWEC members' aggregate average deficiency for each month for the four years prior to 1984 was 14.7 MW. Since the implementation of the Extended Weekly Studies Program in 1984, only one deficiency has been recorded, for an average deficiency per month for 1985 of 1.4 MW (Exh. HO-NRR-3).

screening process, MMWEC analyzes the costs of all units which are available for sale, either through offers made through NEPOOL or based on direct contacts with other utilities (Tr. I, p. 103). This analysis compares the average costs of the available units over a range of capacity factors and under various fuel price scenarios (Tr. I, pp. 101-102).

The second stage of the process utilizes an optimizing methodology, the Westinghouse Automatic Generation Planning Model ("AGP Model"), to identify which among the "most promising alternatives" identified in the screening analysis offers the lowest present value of fixed and variable power supply costs (Exh. HO-TSPP-2; Tr. I, pp. 106-107, 116; Exh. HO-8). MMWEC runs the AGP model under a number of different scenarios to evaluate the sensitivity of the resource to those factors (e.g., fuel costs, capital costs, availability factors) "which would have significant impacts on the economics of this supply resource" (Tr. I, pp. 109-111).

MMWEC has compared the costs of existing oil-fired resources against costs associated in the short run with a range of existing non-oil-fired generating plants and in the long run with new, generic, conventional generating units (Tr. I, p. 110; Exh. HO-GI-4; Exh. HO-TSPP-2).

MMWEC asserts that based on its review of its options, the Company is negotiating with a number of New England utilities "to contract for the purchase of capacity and energy from a variety of existing oil-fired generating facilities for a period of up to ten years to supply the major portion of the projected capacity shortfall" (Exh. HO-AS-1; Exh. HO-AS-3; Exh. HO-CSS-12). Also, MMWEC recently executed agreements with (1) Eastern Utilities Associates for the exchange of peaking capacity for intermediate capacity from November 1986 through October 1995 (Exh. HO-AS-10), and (2) Northeast Utilities for a purchase of 50.8 MW from its Middleton and Montville stations from November 1986 through October 1992 (Id.).

In support of such additions, MMWEC provided evidence of the kinds of analyses and recommendations it offered to member systems regarding these supply additions (Exh. HO-10). These analyses show MMWEC's use of its generation expansion planning techniques to indicate the economics of a particular proposed resource addition compared to MMWEC's generic long-run generation expansion plan (Exh. HO-10).

ii. Small Power Production/Cogeneration Costs

As the methodology for including economical small power production and cogeneration resources into members' resource plans, MMWEC has developed and begun to implement its standard offer contract for obtaining power from "qualifying facility" projects. MMWEC states that the standard offer contracting approach enables the Company to compare the present value of a stream of payments expected to be paid to a QF over the life of a contract, against the present value of an individual member's long-run avoided costs (including energy and capacity components of a conventional resource supply mix that excludes such QF projects) (Exh. HO-SPP-1; Exh. HO-SPP-3; Exh. HO-SPP-4). Such a comparison enables MMWEC to (a) determine whether the projected payments to the QF are at or below avoided costs, and (b) identify which purchases could reduce members' power costs relative to a conventional power supply mix (Exh. HO-SPP-3; Exh. HO-SPP-5; Tr. I, p. 104; Section III.D.1.c.iii, supra).

MMWEC states that in the future it intends to issue a standard offer contract more in line with the "auction process" recently established by the Massachusetts Department of Public Utilities for contracts between private electric companies and QFs (Tr. I, pp. 127-129). In this process, prospective QF suppliers would offer bids to MMWEC in response to a "request for proposals" ("RFP") to supply power at or below MMWEC members' published avoided costs. This process would enable MMWEC to identify which projects would be appropriate to sign agreements with, in order to minimize members' power supply costs.

MMWEC has not set a schedule for issuing a new RFP to supply MMWEC with QF power using a revised standard offer contract. Nor has the Company set a target for the amount of QF resources MMWEC hopes to obtain through such a mechanism. MMWEC asserts it does not want to establish capacity or energy targets because the Company expects to develop the appropriate amount of QF resources through least-cost supply plans in the future (Exh. HO-SPP-10; Exh. HO-SPP-11).

iii. Demand-Management Program Costs

MMWEC states it is beginning to put into place the kinds of data-collection and analytic procedures necessary to support the Company's goal of obtaining new cost-effective power supplies through additional load-management and conservation programs (Exh. HO-1, Section X, p. 5; Exh. HO-AS-1).

For example, in response to the Siting Council's order in its previous decision that the Company provide a "comprehensive and aggressive plan to implement demand reduction programs...for the forecast period," Massachusetts Municipal Wholesale Electric Company, 11 DOMSC 237, 284 (1984), MMWEC prepared and filed a January 1985 "Plan for Determining Cost-Effective Load Management Strategies for Member Municipal Utility Systems" (Exh. HO-1, Section X). In that MMWEC provided the Siting Council with a plan that identified a set of detailed steps[22] and time frames that MMWEC claimed would guide its staff's and its members' appraisal of demand-management potential, the Siting Council finds that MMWEC has complied with that part of the condition in the Siting Council's previous order that required MMWEC to submit a plan for implementing demand reduction programs.

22/These steps include: (1) listing potential load management devices along with their costs and effects on load shapes; (2) developing new computer software to simulate the dispatch of electricity under varying load-management program implementation assumptions; (3) determining existing load-management efforts of members; (4) setting goals and program constraints for individual members; (5) determining load and end-use characteristics of individual members; (6) modeling load-management strategies to determine capacity savings; and (7) issuing a report describing the results of the modeling efforts and ranking potential strategies (Exh. HO-1, Section X).

While the Company has complied with the letter of that condition by merely filing a plan, the Company's actions subsequent to filing the plan raise serious questions as to the Company's intentions and ability to implement demand management planning and strategies as indicated in MMWEC's plan. For example, MMWEC also provided an internal March 1986 report updating the status of the Company's and members' demand-side planning efforts (Exh. HO-23, Attachment 4). In this report, MMWEC explained that it "is beginning the process of integrating demand and supply side planning" (Id., p. 1). The report offered preliminary estimates of the costs and benefits of four conservation programs, and described a three-to-four year strategy for integrating demand-reduction goals into load forecasts and supply plans (Id., Attachment 1). MMWEC also provided supporting documents, including a report compiling information on "No-Cost"/"Low-Cost" Programs (Exh. HO-22, Attachment 1; Exh. HO-CLM-1); a brochure describing a "Least-Cost Utility Planning Seminar" sponsored by MMWEC for its members (Exh. HO-23, Attachment 5); a listing of members' conservation and load-management programs (Exh. HO-CLM-4); and other materials indicating various reports on demand management that were provided by MMWEC to members (Id., Attachments 2, 3, 6, 7; Tr. II, pp. 45-46; Exh. JJB-3).

In recent submissions to the Siting Council regarding the status of the Company's efforts to incorporate analyses of demand-management options into its resource planning process, MMWEC indicated that: (1) the Company issued an RFP for outside consultants to prepare a "Demand-Side Capacity Assessment" in January 1987, an analysis designed to provide cost information on demand-management program opportunties, benefits and costs; (2) the MMWEC membership had voted to remove $300,000 in fiscal year 1987 funding for that analysis; and (3) MMWEC still intends to select a contractor from those who respond to the RFP, and to fund that contractor's work to perform the Demand-Side Capacity Assessment[23] (Exh. HO-CLM-5, p. 2, and Attachments; Tr. II, pp. 47-48, 63).

23/In a late-filed exhibit submitted by MMWEC on July 7, 1987, MMWEC reported: "the MMWEC Board [footnote continued on next page]

Further, MMWEC's witness, Mr. Boudreau, testified that

> MMWEC is looking and is, in fact, really expanding it's [sic] activities in looking at integrating both the demand and supply side. It's particularly important at this point in time in M.M.W.E.C's development because of the need to identify additional supplies or demand side resources to meet deficiencies that were projected to occur in the early 1990s

(Tr. II, p. 61). Mr. Boudreau described a document developed by MMWEC and provided to members which indicated the "least-cost" planning process and criteria that MMWEC is proposing to utilize in the future in establishing its long-run supply plan (Tr. II, p. 63; Exh. JJB-4). According to Mr. Boudreau, this approach would compare resource alternatives on a common basis -- in terms of their marginal cost of supply. Mr. Boudreau indicated that when MMWEC reaches "the point where the marginal supply curve and the marginal demand curve cross, that is the point at which we have the least cost program for supply the requirement through both the combination of demand side programs and supply resources" (Tr. II, pp. 63-64).

2. <u>Comparison of Alternatives on an Equal Footing</u>

MMWEC has supplied information indicating that the Company currently has in place a set of planning methodologies and resource plans typically associated with a wholly conventional generation-expansion-planning approach, adjusted to reflect the inclusion of limited purchases from QFs at or below members' avoided costs and an insignificant level of capacity from demand-management options.

[footnote continued from previous page] of Directors voted not only to fund the assessment of [sic] its June 3, 1987 meeting, but also voted to commence contract negotiations with Applied Management Services Incorporated of Silver Spring, Maryland (AMS) to perform the Assessment. During negotiations, however, AMS indicated it would need an additional $16,000 over and above its original bid price. This necessitated a further review of the other bidders. This further review DOES NOT MEAN that MMWEC will not fund or conduct the Demand-Side Capacity Assessment. Rather, this further review is necessary to insure acceptance of the most cost-effective proposal. The MMWEC Board of Directors is scheduled to select a final bidder at its August, 1987 meeting" (Exh. HO-CLM-5(a), p. 2).

The Company's long-range resource screening process and use of the Westinghouse Automatic Generation Planning model are likely to produce information regarding which resources, among a variety of conventional power supply options, would minimize members' power supply costs. The Company supports its long-range generation-expansion planning activities with an innovative technique for minimizing members' costs for obtaining power from existing generation and purchase options. The evidence shows that this Extended Weekly Studies Program offers members a means for pooling and juggling existing generation resources on a week-to-week and month-to-month basis in order to save each participating member's costs (Exh. WHD-1; Exh. WHD-2; Tr. I. pp. 9-11).

The Company has provided considerable documentation in support of its claims that it intends to integrate demand-side program analysis and planning into its overall resource development process. For example, MMWEC established two new membership committees -- the Power Resource Development Committee and the Load Management and Conservation Committee -- to work with the Company's Power Planning and Operations Committee to ensure that in the future "recommendations could go out to the members which embody a least-cost alternative for meeting those deficiencies" (Tr. II, pp. 61-62; Exh. HO-23, Attachment 5).

However, these claims remained unsubstantiated. Virtually all of the evidence indicates that MMWEC has failed to act upon its intentions and actually evaluate resource options on an equal footing:

(1) MMWEC's statements at the January 27, 1987 hearing that the Company plans to integrate demand-side and supply-side options into a least-cost planning approach in the future (Tr. II, pp. 47-48, 61-64) demonstrate little substantive progress over the Company's March 1986 report on the status of demand-side planning activities at MMWEC (Exh. HO-23, Attachment 4) and over the Company's January 1985 "Plan for Determining Cost-Effective Load Management Strategies for Member Municipal Utility Systems" (Exh. HO-1, Section X).

(2) Further, although MMWEC states that it intends to commence its study of "Demand-Side Capacity Assessment" sometime after the summer of 1987, this assertion presumes that MMWEC will actively encourage the membership and the MMWEC Board of Directors to fund this assessment. The Siting Council notes, however, that this funding is at least questionable, in light of a pattern of delays over the past year (Exh. HO-CLM-5(a); Exh. HO-CLM-5, p. 2, Attachments; Tr. II, pp. 47-48, 63).

(3) MMWEC concedes that its Extended Weekly Studies Program and its Automatic Generation Planning Model -- the methodologies the Company is now using to analyze short-run and long-run costs associated with various resource plan configurations -- are not capable of analyzing demand management and therefore cannot inform MMWEC whether implementing conservation and load-management programs to reduce demand would be a cheaper alternative for a member system that supplying that demand through conventional supply-side options (Tr. I, pp. 41-43).

(4) In the absence of any existing analytical capabilities that place demand-management options on an equal footing with supply-side options, MMWEC's activities in actually integrating conservation and load management into its resource plans are limited to holding seminars on least-cost planning, providing information on low-cost and no-cost programs, and planning for members to implement a few small-scale demand-management programs as part of MWMEC's "contingency resources" (Exh. JJB-3; Exh. HO-22; Exh. HO-23; Exh. HO-CLM-4). See Section III.D.1.c.iv and v, _supra_. In some cases, individual towns' own efforts to implement conservation and load-management programs are more extensive than such minimal system-wide efforts (Exh. HO-CLM-4).

Overall, then, the Company has presented a list of claims of "good intentions" but has failed to establish that it has taken adequate steps to fulfill the statements of good intent.

Finally, in Boston Edison Company, EFSC 85-12 (Phase II), 15 DOMSC 287, 341-349, the Siting Council found that even though that company had developed and used techniques for analyzing the costs and benefits of demand-management options, it still did not have a supply planning process that treated demand-side and supply-side options on an equal footing, since that company was not implementing all of the demand-management strategies its own analyses showed to be cost-justified. In the instant case, MMWEC is still at the stage of promising to put into place the methods that will enable the Company to analyze, much less implement, additional cost-justified demand-side strategies along with supply-side strategies.

Accordingly, the Siting Council finds that (1) MMWEC's supply plan is not based upon an adequate consideration of conservation and load management, and (2) MMWEC does not evaluate resource options on an equal footing in its short-run or long-run planning processes.

3. Conclusions

In that MMWEC has failed to demonstrate that (1) its supply plan is based upon an adequate consideration of conservation and load management and (2) its planning process evaluates demand-side and supply-side options on an equal footing, the Siting Council finds that MMWEC's supply plan does not ensure a least-cost energy supply, as required in the Siting Council's enabling statute.

This failure is unacceptable simply from the perspective of violating the Siting Council's requirement that the Company provide a reliable, least-cost power supply to MMWEC members' customers. But MMWEC's failing is particularly troublesome in light of evidence that: (1) over the past two years, while MMWEC has been promising to integrate demand and supply planning but has undertaken only token steps to do so, MMWEC has entered into various short-run and long-run agreements to purchase energy and capacity; and (2) the Company will be deciding which options are preferable to pursue on the basis of cost advantage so that members can decide which options to firm up in order to avoid capacity deficiencies in the short run; and (3) MMWEC still needs to identify how it intends to obtain additional resources to avoid system-wide capacity deficiencies in the long run. In effect, MMWEC's intentions to implement a "least-cost" planning process in the future, as well as MMWEC's minimal efforts to implement anything but supply-side resources in the past, are "too little too late."

F. Diversity of Supply

As part of Condition 4 of its last decision, the Siting Council required MMWEC to provide "a comprehensive and aggressive plan to implement demand-reduction programs and identify potential alternative sources of generation, including coal, cogeneration, imported power, renewables and other sources for the forecast period." Massachusetts Municipal Wholesale Electric Company, 11 DOMSC 237, 284 (1984). This condition followed from other statements by the Siting Council that "small scale and conservation 'supply' may provide diversification and cost benefits that warrant a separate review" (Id., p. 271).

In the instant proceeding, MMWEC provided evidence that, through the mechanism of its new standard offer contract, MMWEC had entered into agreements with developers of four QF projects to provide energy and capacity to members at or below their long-range avoided costs (Exh. HO-12; Exh. HO-SPP-1; Exh. HO-CSS-4; Tr. I, pp. 67-68). As all of these projects are small in size (i.e., ranging from one to ten megawatts) and three of them plan to use renewable resources (i.e., wood or water) as their source of energy, the addition of these new projects as part of MMWEC's resource supply will undoubtedly enhance the diversity of the MMWEC system's generation and fuel mix.

While MMWEC deserves some recognition for having been the first utility in Massachusetts to issue a standard offer contract for QF power, the Siting Council cannot find, on the basis of the record, that MMWEC's efforts to date represent an aggressive program to diversify the system's supply mix. MMWEC's original target for its initial standard offer contract offering was 50 MW, representing approximately five percent of the system's total capacity. However, only 22 of MMWEC's 33 members elected to participate, for a total of 16.5 MW of capacity (Exh. HO-SPP-1, Attachment). Further, MMWEC has not set a date or capacity target for the amount of QF resources it hopes to obtain by means of its next solicitation, even though MMWEC expects to need to add capacity and energy in the future (Tr. I, pp. 127-129)

So, while MMWEC has taken a small and important step in the right direction in terms of diversifying the fuel/technological/size make-up of the system's generation mix, the addition of such a small amount of new planned renewable resources is unlikely to significantly affect the bottom line of MWMEC's expected fuel mix in the future. In contrast, the Company's supply plan also includes 120 MW from the 1150-MW Seabrook 1 nuclear power plant (Exh. HO-1, App. I-1).

According to MMWEC's projections, over the next five years the system's fuel mix will become more reliant upon nuclear energy (from 33 percent of the 1985 fuel mix, to 43 percent in 1990, if Seabrook 1 comes on line in that interim), and slightly less dependent upon oil (from 30 percent to 25 percent). Renewable resources and energy provided by QF projects are expected to contribute only 4 percent in 1985, and 6 percent by 1990. (Exh. HO-GI-1.)

In that MMWEC has filed a plan to diversify its fuel mix away from oil, the Siting Council finds that MMWEC has complied with that portion of Condition 4 from the previous order that required MMWEC to provide a plan to identify alternative sources of generation, including cogeneration, renewables and conservation.

G. Summary of the Supply Plan Analysis

In that (1) MMWEC has failed to provide a supply plan that provides adequate supplies in the long run, and (2) MMWEC has failed to establish that its planning process ensures a least-cost power supply for customers, the Siting Council hereby rejects MMWEC's supply plan.

IV. SUMMARY

In approving MMWEC's demand forecast and rejecting MMWEC's supply plan, the Siting Council notes that its findings in this case relate only to the Company's ability to forecast and plan for its 33-member system as a whole. See Section I.A, supra. Although the evidence raises serious questions about the adequacy and cost of some members' supply plans, the record in this proceeding is insufficient to make any specific findings regarding each member's forecast and supply plan.

Therefore, the Siting Council's findings on MMWEC's forecast and supply plan do not operate as an approval or rejection of the forecasts and supply plans of the member towns.[24] Further, the Siting Council ORDERS MMWEC in its next filing to supply sufficient information on member towns' forecasts and supply plans to enable the Siting Council to fully evaluate (a) the reviewability, appropriateness and reliability of MMWEC's demand forecast for each member, and (b) the adequacy, diversity and cost of each member's individual supply plan.

24/This distinction is significant in light of G.L. c. 164, sec. 69I, which states that a "company shall not commence construction of a facility at a site unless the facility is consistent with the most recently approved long-range forecast or supplement thereto." The Siting Council's decision in this proceeding would bar MMWEC as an entity from constructing a jurisdictional facility until the Siting Council has (1) approved an MMWEC demand forecast and supply plan and (2) found that the proposed facility is consistent thereto; however, the Siting Council's decision in the instant proceeding would not preclude an MMWEC member from seeking the Siting Council's approval to construct a jurisdictional facility.

V. <u>DECISION AND ORDER</u>

The Siting Council hereby approves the demand forecast and rejects the supply plan that together comprise the 1985 Long-Range Forecast of Electricity Needs and Resources filed by MMWEC on behalf of its 33 members.

The Siting Council orders MMWEC to file its next long-range forecast on December 15, 1987.

The Siting Council further orders MMWEC and its members to disaggregate their industrial databases in compliance with the Siting Council's Rule 63.7(2) and their commercial databases in a manner that captures electricity-consumption establishments. The Siting Council further orders MMWEC to comply with these requirements in the Company's first forecast filing that occurs after twelve months from the date of this decision.

The Siting Council further orders MMWEC in its next filing to supply sufficient information on member towns' forecasts and supply plans to enable the Siting Council to fully evaluate (a) the reviewability, appropriateness and reliability of MMWEC's demand forecast for each member, and (b) the adequacy, diversity and cost of each member's supply plan.

Robert D. Shapiro

Robert D. Shapiro
Hearing Officer

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of July 28, 1987, by the members and designees present and voting: Sharon M. Pollard (Secretary of Energy Resources); Sarah Wald (for Paula W. Gold, Secretary of Consumer Affairs); Fred Hoskins (for Joseph D. Alviani, Secretary of Economic Affairs); Stephen Umans (Public Electricity Member); Joseph W. Joyce (Public Labor Member).

Ineligible to vote: Elliot J. Roseman (Public Oil Member). Absent: Stephen Roop (for James S. Hoyte, Secretary of Environmental Affairs); Madeline Varitimos (Public Environmental Member); Dennis J. LaCroix (Public Gas Member).

Sharon M. Pollard

Sharon M. Pollard
Chairperson

7/30/87
Date

Table 1

Energy and Peakload Forecasts for MMWEC and MMWEC Members
Compound Annual Growth Rates -- 1984-1994

Member	Energy	Peak*
Ashburnham	2.1 %	2.1 %
Belmont	1.4	1.4
Boylston	2.4	2.4
Braintree	2.2	2.6
Chicopee	1.1	1.1
Concord	2.6	2.8
Danvers	3.4	3.9
Georgetown	2.7	2.8
Groton	2.4	2.7
Hingham	2.3	2.3
Holden	2.7	3.0
Holyoke	1.8	2.0
Hudson	2.8	3.3
Hull	4.0	3.9
Ipswich	1.9	2.4
Littleton	6.7	7.2
Mansfield	3.3	3.4
Marblehead	1.3	1.4
Merrimac	2.9	2.9
Middleborough	2.3	2.6
Middleton	3.2	4.6
North Attleborough	3.5	3.3
Paxton	1.5	1.6
Peabody	2.6	2.8
Princeton	3.2	3.8
Reading	3.7	3.8
Rowley	2.7	3.1
Shrewsbury	2.6	3.0
South Hadley	1.7	1.1
Sterling	2.4	2.9
Templeton	1.7	2.1
Wakefield	2.6	2.5
West Boylston	1.8	2.3
Westfield	2.5	2.5
MMWEC combined system	2.7 %	2.9 %

source: Exh. HO-1, Table III-1

* MMWEC forecasts that winter peaks for all systems except Braintree, Concord, Danvers, Holyoke, Peabody, Reading, South Hadley, Wakefield, and Westfield, for which MMWEC expects summer peaks.

Table 2

MMWEC Aggregate System Demand Forecast Summary

Annual Requirements:

	Annual Energy Requirements (GWH)			Average Annual Compound Growth Rate
	1986	1990	1994	1984-1994
Residential	1594	1660	1722	1.2 %
Commercial	766	872	1002	3.1 %
Industrial	1617	1910	2225	4.3 %
TOTAL	4576	5080	5628	2.7 %

Non-Coincident Peak Requirements:

	Peakload (MW)			Growth Rate
	1986	1990	1994	1984-1994
winter	880	976	1080	2.9 %

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source: Exh. HO-1, Table III-1

Table 3

MMWEC Base Case
Aggregate Resources and Requirements[1] (MW)

	86/87	87/88	88/89	89/90	90/91	91/92	92/93	93/94
Non-Coincident Peakload[2]	881	901	924	953	984	1013	1050	1082
Load & Reserve Requirement[3]	974	1048	1056	1074	1121	1154	1197	1233
Existing Resources	1137	1139	981	977	932	932	886	886
Capacity Additions:								
Seabrook[4]	-	80	80	80	97	97	97	97
Cleary 9	-	-	9	9	9	9	9	9
H.Q. II	-	-	-	-	56	56	56	56
Total Resources	1137	1219	1070	1066	1094	1094	1048	1048
Surplus/ (Deficit)	163	171	14	(8)	(27)	(60)	(149)	(185)

source: Exhibit JJB-1

notes:
1. Excludes requirements and resources of four towns (Belmont, Concord, Merrimac, and Rowley) that are all requirement customers of non-MMWEC utility companies (Tr. I, pp. 129-130).
2. Based on 1986 MMWEC forecast (Exh. JJB-1); aggregate peak projected for winter, although a few towns are expected to be summer peaking systems (Tr. II, pp. 8-9).
3. Including impact associated with MMWEC not havaing to carry reserve on load met by contract demand services provided by other utility companies (Exh. HO-NRR-1).
4. Reflects November 1987 in-service date for Seabrook 1 and MMWEC's buy-back agreement with Public Service Company of New Hampshire (Exh. HO-CSS-6).

Table 4

MMWEC's Additional Resource Requirements
With Short Run Options[1]

Short Run Options	86/87	87/88	88/89	89/90	90/91
Pt. Lepreau 1 Contract Extension[2]	-	-	100	100	-
Existing Contract Demand Extensions[3]	-	-	-	2	70
Standard Offer Contract with Small Power Projects	-	-	16	16	16
Load Management Programs	-	-	7	15	15
Conservation Programs	-	7	14	21	28
TOTAL	0	7	137	154	129
MMWEC's Base Case Including Short Run Options:					
Base Case Capacity Surplus/(Deficiency)[4]	163	171	14	(8)	(27)
Net Surplus/(Deficiency) With Short-Run Options	163	178	151	146	102

source: Exh. JJB-3; Table 3, supra.

notes:
1. MMWEC calls these its "Contingency Resources" (Exh. JJB-3).
2. These amounts reflect the Siting Council's adjustments to the data in Exh. JJB-3, to account for constraint on MMWEC's ability to rely for planning purposes on the third year of the Pt. Lepreau contract extension due to transmission-related uncertainties. See Section III.D.1.c.i, supra.
3. See Footnote 11, supra.
4. See Table 3, supra.

Table 5

MMWEC -- Short Run Contingency Analysis

1. Cancellation of Seabrook 1

	(a) Base Case Surplus/ (Deficit)	(b) Loss of Seabrook	(c) Contingency Surplus/ (Deficit) (a-b)	(d) Short Run Options	(e) Possible Surplus/ (Deficit) (c+d)
1986/87	163	0	163	0	163
1987/88	171	(80)	91	7	98
1988/89	14	(80)	(66)	137	71
1989/90	(8)	(80)	(88)	154	66
1990/91	(27)	(97)	(124)	129	5

2. Delay of Small Power Production/Cogeneration Projects

	(a) Base Case Surplus/ (Deficit)	(b) Short Run Options	(c) Base Case With Options (a+b)	(d) Delay of SPP/C	(e) Possible Surplus/ (Deficit) (c+d)
1986/87	163	0	163	-	163
1987/88	171	7	178	-	178
1988/89	14	137	151	(16)	135
1989/90	(8)	154	146	(16)	130
1990/91	(27)	89	62	-	62

sources: Exh. JJB-2; Exh. JJB-3; see also Tables 3 and 4, supra.

Table 6

MMWEC Members -- Contingency Analysis
With Short Run Options and Without Seabrook 1[a]

	Expected Additional Capacity Need (in KW)				
	1986/87	1987/88	1988/89	1989/90	1990/91
Ashburnham	-[b]	100	-	300	-
Boylston	-	300	-	-	100
Braintree	-	-	-	-	-
Chicopee	-	-	32,300	31,700	28,000
Danvers	-	3,400	-	6,500	8,800
Georgetown	-	-	-	-	300
Groton	-	-	-	-	100
Hingham	-	1,600	2,600	5,900	5,000
Holden	-	-	-	1,100	1,200
Holyoke	-	-	-	-	-
Hudson	-	1,900	-	1,700	1,200
Hull	-	-	-	-	-
Ipswich	-	1,800	1,500	3,900	4,400
Littleton	-	-	-	2,900	5,100
Mansfield	-	-	-	2,000	1,700
Marblehead	-	-	-	-	-
Middleboro	-	-	-	-	2,300
Middleton	-	-	-	-	-
North Attleborough	-	-	-	3,700	1,600
Paxton	-	-	-	100	-
Peabody	-	-	-	-	-
Princeton	-	800	1,600	1,900	1,900
Reading	-	-	-	-	16,400
Shrewsbury	-	-	-	-	-
South Hadley	-	5,400	5,500	4,400	2,500
Sterling	-	800	-	800	700
Templeton	-	-	-	-	-
Wakefield	-	2,700	-	2,400	3,300
West Boylston	-	-	-	-	-
Westfield	-	-	-	-	-
AGGREGATE MMWEC NEED:[c]	-	-	-	-	35,000

sources and notes:

a. These resources reflect those shown in Table 4 and Table 5 (part 1), <u>supra</u>. Allocation of Seabrook 1 reductions, Pt. Lepreau contract extensions, standard offer contract amounts, and contract demand extensions, are based upon each town's actual share of these specific projects (Exh. JJB-1, p. 3; Exh. HO-SPP-1; Exh. HO-AS-6; Tr. II, p. 37). Allocation to individual towns of the capacity estimated by MMWEC to be available from load management and conservation programs are based upon Siting Council calculations of each individual town's percentage share of system non-coincident peak (See Exh. JJB-1).

b. The "-" notation in any column reflects adequate supplies in that year; all amounts are rounded to the nearest hundred kilowatts.

c. See Table 5 (part 1), column e.

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 service of the decision, order or ruling of the Siting Council or within such further time as the Siting Council may allow upon request filed prior to the expiration of 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. (Sec. 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 Wakefield Municipal Light Department for Approval of the Third Long-Range Forecast of Natural Gas Requirements and Resources	)	EFSC 86-2

Final Decision

Robert D. Shapiro
Hearing Officer
September 10, 1987

On the Decision:

Sheri L. Bittenbender

TABLE OF CONTENTS

The Energy Facilities Siting Council hereby APPROVES the sendout forecast and supply plan filed by Wakefield Municipal Light Department for the five years from 1986-87 through 1990-91.

I. INTRODUCTION

A. Background

Wakefield Municipal Light Department ("Wakefield" or "Department") distributes and sells gas to 4860 firm customers in the town of Wakefield. The Department has 1830 heating customers[1], 2863 residential customers without gas heating, 150 commercial customers and 17 municipal customers (Exh. HO-S-1).

Wakefield is a total requirements customer of Boston Gas. The Department has no facilities and does not intend to build or obtain any such facilities during the forecast period.

Wakefield's forecast of sendout by customer class for the heating and non-heating seasons is summarized in Table 1 (Exh. HO-SO-1). Wakefield projects an increase of total normalized firm sendout from 360.9 MMcf in 1986-87 to 368.9 MMcf in 1990-91, representing a compound increase of 0.5 percent per year (id.).

Wakefield's previous forecast was approved by the Energy Facilities Siting Council ("Siting Council") without conditions. Wakefield Municipal Light Department, 15 DOMSC 31 (1986).

B. History of the Proceeding

On October 30, 1986, the Department filed its sendout forecast and supply plan (Exh. HO-1). The Department provided notice of the proceeding by publication and posting in accordance with the directions of the Hearing Officer.

1/ Wakefield's heating class consists of both residential and commericial heating customers.

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 requires 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. Berkshire Gas Company, EFSC 86-29, p. 2 (1987). Boston Gas Company, EFSC 84-25, pp. 19-20 (1986).

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 forecasting 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. Berkshire Gas Company, EFSC 86-29, pp. 2-3 (1987). Bay State Gas Company, 14 DOMSC 143, 150 (1986). Boston Gas Company, EFSC 84-25, p. 8 (1986).

B. Normal Year

1. Description

Wakefield forecasts sendout for residential non-heating, commercial and municipal customers by calculating customer use factors for each class based upon the previous year's experience, adjusting these factors for the expected effect of conservation, and multiplying these revised usage factors by the expected number of customers in each class (Exh. HO-1, Worksheet Forms 1, 3 and 5). For its heating customers, Wakefield calculates separate use factors for heating and non-heating use and normalizes the heating use factor. The normalized heating-use factor and the non-heating use factor are reaggregated and adjusted for conservation before multiplying by the expected number of customers in the class (Exh. HO-S-5, Worksheet Form 2). Wakefield's normal year weather standard is 5758 degree days ("DD") (Exh. HO-DD-1).

Using this methodology, the Department anticipates a 0.5 percent compound annual increase in total firm sendout over the forecast period from 360.9 MMcf in 1986-87 to 368.9 MMcf in 1990-91 (id., Table G-5). This increase is attributable to anticipated additions of (1) 50 customers per year in the heating class[2] (Exh. HO-1, p. 1) as adjusted for conservation by 1.5 percent for both heating customers and residential non-heating customers, and (2) five customers per year in the commercial class adjusted by 1.0 percent for municipal and commercial customers (id., Worksheet Form 3). The Department's customer growth estimates are designed to reflect historical experience of customer addition and customer loss (id., p. 1; Exh. HO-S-6), while its conservation expectations are drawn from average national figures (Exh. HO-1, p. 1).[3]

2. Analysis

As part of its forecast, the Department submitted copies of the worksheets used for calculating its forecasted normal sendout. These detailed worksheets enable a third party to understand and reproduce the Department's forecast methodology. Accordingly, the Siting Council finds that the Department's normal year methodology is reviewable.

2/ Ten of these additional customers represent conversions from the non-heating class and, therefore, represent a loss in that class (Exh. HO-1, p. 1).

3/ The Department states that it has inadequate historical data to derive company-specific estimates (Exh. HO-1, p. 1).

In order to determine the appropriateness and reliability of Wakefield's methodology, however, the Siting Council closely examined (1) the expected change in customer numbers, (2) the selection of normal annual degree days, and (3) the manner in which the conservation adjustment was applied.

In regard to customer numbers, the Department submitted a document which set forth the disaggregated number of customer additions and losses experienced between 1984-85 and 1985-86 (Exh. HO-S-1). Between the 1984-85 split year[4] and the 1985-86 split year, the heating class increased by 67 customers, of which 30 were conversions from the residential non-heating class (Exh. HO-S-2). The residential non-heating class decreased by nine customers, and the commercial class lost six customers (Exh. HO-S-3). The Department states that the loss of commercial customers will be reflected in future sendout forecasts (HO-S-6).

In light of this historical information, the Siting Council finds that the Department's estimates, in general, are reasonable. Wakefield has estimated new heating customers at three customers more than the growth experienced in the previous period. The Department continues to plan for a small addition of commercial customers. In considering residential non-heating to heating conversions, however, the Department plans for only one-third of the conversion activity experienced between 1984-85 and 1985-86. This represents a conservative estimate of decreases in the residential non-heating class, but may underestimate additions to the heating class. Still, the Siting Council finds that for a company the size of Wakefield, this method of forecasting customer numbers is both appropriate and reliable.

The Department projects normal year sendout on the basis of a 5758 DD normal year (Exh. HO-DD-1). The average number of calendar year degree days for the past five years is 5602 (Exh. HO-DD-2); in none of the past five years has the annual total degree days equalled or exceeded 5758 (id.). In fact, the coldest year experienced was

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

1984, when the Department experienced 5721 DD (id.). The Department failed to provide an explanation for its selection of 5758 degree days as a normal year standard. While the Siting Council finds that the 5758 DD normal year is appropriate for this review, the Siting Council ORDERS the Department to (1) develop a systematic methodology for the selection of its normal year degree day standard and (2) submit a revised degree day standard along with supporting analysis as part of its next filing.

The Department's application of its conservation estimate also raises questions in regard to the forecast for the heating class. Currently, Wakefield determines temperature-sensitive use per customer by subtracting non-temperature-sensitive use per customer from total daily use per customer. The total use figure is adjusted for conservation before the operation, however, and the non-temperature-sensitive use is not. The Siting Council finds this order of operations to be inconsistent. The methodology, as presented, results in the temperature-sensitive use being reduced by more than 1.5 percent, while non-temperature-sensitive use is not affected at all. Although total annual sendout predictions are not affected, the distribution of forecasted sendout between the heating and non-heating seasons is distorted. The Siting Council finds, however, that this flaw in the Department's methodology does not render the sendout forecast unreliable. The Siting Council, however, ORDERS the Department to (1) evaluate its order of operations in applying its conservation estimate for purposes of its sendout forecast for the heating class and (2) submit a more consistent process as part of its next filing.

In conclusion, the Siting Council finds that Wakefield's normal year methodology is reviewable, appropriate and reliable.

C. Design Year

1. Description

The design year for which Wakefield plans is based on 6,316 DD (Exh. HO-DD-2). The Department's design year forecasting methodology differs from its normal year forecast only in the forecast for its heating class customers. In the design year heating class forecast, the Department uses the same temperature-sensitive and non-temperature-sensitive use factors as derived in its normal year forecast. The temperature-sensitive factor is multiplied by design year DD and the number of customers; the non-temperature-sensitive factor is multiplied by the number of customers. The sum of these two products represents the heating class sendout that Wakefield plans for under design weather conditions.

Using this methodology, the Department anticipates a 0.6 percent compound annual increase in design sendout from 378.4 MMcf in 1986-87 to 387.4 in 1990-91.

2. Analysis

In that the methodology used to forecast design year sendout is nearly identical to that used to forecast normal year sendout, the Siting Council's previously articulated concerns regarding normal year methodology and inputs, i.e., application of conservation estimates, forecast of customer numbers, (see Section II.B.2., *supra*), need not be detailed here. In a review of the sendout forecast of a larger company, the Siting Council would carefully review the assumption that there is no variation in consumption from a normal to a design year for all customer classes except the heating class. For a company of Wakefield's size and resources, however, the Siting Council finds that this assumption is appropriate.

In regard to the design year DD, the Department did not provide an explanation for its selection of 6316 degree days. While the Siting Council finds that Wakefield's DD standard is appropriate for this review, the Siting Council ORDERS the Department to (1) develop a systematic methodology for the selection of its design year degree day standard and (2) submit a revised degree day standard along with supporting analysis as part of its next filing.

Accordingly, the Siting Council finds that Wakefield's design year methodology is reviewable, appropriate and reliable.

D. Peak Day[5]

1. Description

The peak day for which the Department plans is based upon the number of degree days experienced on the coldest day of the last heating season before the forecast. In this case, the coldest day was a 55 DD day on January 15, 1986 (Exh. HO-1, p. 2). The forecast of peak day sendout is calculated by summing the daily average of heating season sendout for the three non-heating classes with the sendout predicted for the heating class on a 55 DD day (Exh. HO-SO-3).

Using this peak day methodology, the Department projects that peak day sendout will be 2322 Mcf in 1986-87 and 2365 Mcf in 1990-91.

The Department asserts that it also computes a more extreme peak day sendout forecast using what it describes as a design peak day standard. This standard is 73 DD, based on an actual 73 degree-day day which occurred on February 9, 1934. Using the 73 degree-day figure, the Department anticipates that peak day sendout will be 2907.1 Mcf in split year 1986-87 and 2960.2 Mcf in split-year 1990-91.

2. Analysis

In that the figures used to forecast peak day sendout are based on the forecast of normal year sendout, the Council's previously articulated concerns regarding normal year methodology and inputs, see Section II.B.2, supra, need not be detailed here. Still, the peak day sendout methodology raises questions regarding Wakefield's peak day standard.

Wakefield uses two different peak day standards in its planning. The Company submitted the 55 DD day in its forecast, and, later in the review, described the 73 DD design peak day which it also uses. While the Siting Council finds this dual approach to be both

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5/ In this decision, the Siting Council uses "peak day" as synonymous with "design day."

appropriate and reliable, it also finds that a more complete analysis of the difference in the impact of these two forecasts on the Company's supply plan is essential for future reviews. Therefore, the Siting Council ORDERS the Department to provide a complete analysis of the impact of these separate forecasts on annual supply planning decisions as part of its next filing.

In conclusion, the Siting Council finds that Wakefield's peak day methodology is reviewable, appropriate and reliable.

E. Summary

In summary, the Siting Council finds that the Department has provided adequate information for the Siting Council to review its forecasts of normal year, design year, and peak day sendout. The Siting Council finds that each of the forecast methodologies is both appropriate and reliable. Accordingly, the Siting Council finds that Wakefield's forecast provides a sound basis for resource planning decisions. The Siting Council also finds, however, that although the Department's normal year and design year degree day standards are appropriate, certain issues must be addressed by the Department before its next filing.

Accordingly, the Siting Council hereby approves the Department'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. Berkshire Gas Company, 14 DOMSC 107, 128 (1986). Holyoke Gas and Electric Light Department, 15 DOMSC 1, 27 (1986). Fitchburg Gas and Electric Light Company, 15 DOMSC 39, 54 (1986). Westfield Gas and Electric Light Department, 15 DOMSC

67, 72 (1986). Fall River Gas Company, 15 DOMSC 97, 111 (1986). While the Siting Council has broadly defined adequacy as the Department'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 transportation projects that are 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.[6] Berkshire Gas Company, EFSC 86-29, p. 17 (1987).

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. Id.

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. Id., p. 18.

The Siting Council also reviews the cost of a utility's supply plan in terms of cost minimization, subject to trade-offs with adequacy of supplies. Id.

6/ 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, EFSC 84-25, p. 33 (1986). Fitchburg Gas and Electric Light Company, 15 DOMSC 39, 53 (1986). Fall River Gas Company, 15 DOMSC 97, 115 (1986). Berkshire Gas Company, 14 DOMSC 107, 127 (1986). Bay State Gas Company, 14 DOMSC 143, 168 (1986). Essex County Gas Company, 14 DOMSC 189, 201-202 (1986).

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 forecasts founded on accurate historical information and sound projection methods. Berkshire Gas Company, 14 DOMSC 107, 128 (1986).

B. Resources

As a total requirements customer, the Department's supply resources are controlled by a contract with Boston Gas which expires in August 1990. Wakefield's contract limit for 1985-86 was 402,029 Mcf (Exh. HO-1, p. 1). Based on a five percent escalation clause contained in the contract, the Department's contract limit at the end of the forecast period would be 513,102 Mcf (id., Table G-24). The Department's contracted maximum daily quantity ("MDQ") also escalates by five percent per year and will increase from 4020 Mcf in 1986-87 to 4886 Mcf in 1990-91 (id.).[7]

C. Adequacy of Supply

In reviewing Wakefield's current supply plan, the Siting Council must determine whether the Department has adequate resources

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7/ The Company's forecast of resources for 1990-91 is based on the assumption that a gas supply contract with identical escalation clauses will be in effect after August 1990.

to meet projected sendout requirements under a reasonable range of contingencies. In that Wakefield is a total requirements customer of Boston Gas, the Siting Council finds that there are no contingencies for which the Department can reasonably plan. If the Department were to lose its only source of supply, it would have very little recourse. Therefore, in this review, the Siting Council examines the Department's "base case" resource plan assuming that Wakefield's contract quantities will be available from Boston Gas. The Siting Council assesses the adequacy of Wakefield's "base case" plan to meet firm sendout requirements under normal, design and peak day weather conditions.

Because Wakefield has no interruptible customers, storage or facilities, the Department's only sendout requirements during a normal year, design year or peak day are those of its firm customers. Throughout the years of the forecast period, Wakefield has sufficient gas in its contract with Boston Gas to meet its sendout requirements under normal year and design year conditions and on either type of peak day based upon either a 55-DD or 73-DD standard (See Table 2).

Accordingly, the Siting Council finds that Wakefield's base case supply plan is adequate to meet its normal year, a design year and peak day requirements during the forecast period.

D. Least-Cost Supply

While the Siting Council has found that Wakefield has adequate resources to meet its forecasted requirements under normal, design and peak day conditions, the Siting Council notes that since 1982-83, Wakefield has experienced growth in its normalized sendout at approximately a two percent compound annual rate (Exh. HO-1, Table G-5). During the same period, however, the Department's contract limits in the Boston Gas contract have grown at an annual rate of five percent (id., Table G-24). Gas supply will continue to grow at an annual rate of five percent until its contract expiration, but Wakefield is projecting an annual compound sendout growth rate of only 0.5 percent (Exh. HO-S-5, Table G-5). Therefore, when the contract expires in August 1990, contracted resources will exceed forecasted normal sendout requirements by more than 30 percent, and exceed forecasted design requirements by over 26 percent (Exh. HO-S-5, Table G-5; Exh. HO-SO-2; Exh. HO-1, Table G-24). The contracted MDQ will exceed forecasted peak day requirements by approximately 100 percent in 1990 for the 55 degree-day estimate and by approximately 60 percent for the 73 degree-day estimate (Exh. HO-S-5, Table G-23, Exh. HO-PD-2).

In light of the increasing disparity between contracted and required volumes, the Siting Council finds that in order to ensure that Wakefield is planning in a manner that ensures a least-cost supply of energy, the Company must provide information regarding its plans for securing new gas supplies upon expiration of its Boston Gas contract. Accordingly, the Siting Council ORDERS Wakefield in its next filing to (1) report on the status of its efforts to obtain new gas supplies upon expiration of its contract with Boston Gas, (2) provide information regarding the Department's goals in securing a new or renegotiated supply contract, and (3) provide the AVL and MDQ the Department intends to secure along with a discussion of the basis on which Wakefield selected those quantities.

E. Summary of the Supply Plan Analysis

The Siting Council has determined that Wakefield's supply plan is adequate and that it ensures a least-cost energy supply.

Accordingly, the Siting Council approves Wakefield's 1986 supply plan.

IV. DECISION AND ORDER

The Siting Council hereby APPROVES the sendout forecast and supply plan filed by the Wakefield Municipal Light Department.

The Siting Council FURTHER ORDERS Wakefield to

(1) develop a systematic methodology for the selection of the Department's normal year degree day standard and submit an explanation of this methodology and its results as part of the Department's next filing,

(2) reconsider the order of operations in applying the Department's conservation estimate to its sendout forecasting process for the heating class and explain the manner in which the conservation adjustment is computed for this class as part of the Department's next filing,

(3) develop a systematic methodology for the selection of the Department's design year degree day standard and submit an explanation of this methodology and its results to the Siting Council as part of the Department's next filing, and

(4) report on the status of its efforts to obtain new gas supplies upon expiration of its contract with Boston Gas, provide information regarding the Department's goals in securing a new or renegotiated supply contract, provide the AVL and MDQ the Department intends to secure along with a discussion of the basis on which Wakefield selected those quantities.

The Siting Council FURTHER ORDERS the Department to file its next long-range forecast on November 1, 1988.

Robert D. Shapiro

Robert D. Shapiro
Hearing Officer

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council by the members and designees present and voting: Sharon M. Pollard (Secretary of Energy Resources); Tim Gailey (for Paula W. Gold, Secretary of Consumer Affairs and Business Regulation); Elizabeth Kline (for James S. Hoyte, Secretary of Environmental Affairs); Dennis J. LaCroix (Public Gas Member); Joseph W. Joyce (Public Labor Member). Absent: Fred Hoskins (for Joseph D. Alviani, Secretary of Economic and Manpower Affairs); Stephen Umans (Public Electricity Member); Madeline Varitimos (Public Environmental Member).

Sharon M. Pollard

Sharon M. Pollard
Chairperson

14 September 1987
Date

TABLE 1

Wakefield Municipal Light Department

Forecast of Sendout by Class

Normal Year

Customer Class	1986-87 Nonheating Season (MMcf)	1986-87 Heating Season (MMcf)	1990-91 Nonheating Season (MMcf)	1990-91 Heating Season (MMcf)
Heating	80.9	187.8	85.8	194.1
Residential Nonheating	32.6	32.6	30.2	30.2
Commercial Nonheating	10.7	10.7	11.6	11.6
Industrial Nonheating	1.8	3.7	1.8	3.6
TOTAL*	126.1	234.8	129.4	239.5

*Includes Company-Use and UFG

Source: Exhibit HO-1, Worksheets Form 1,3, and 5; HO-S-5, Table G-5, Worksheet Form 2

TABLE 2

Wakefield Municipal Light Department

Forecasted Requirements and Resources

	Annual			Daily		
	Normal (MMcf)	Design (MMcf)	Contract Quantity (MMcf)	Using 55 DD (Mcf)	Using 73 DD (Mcf)	MDQ (Mcf)
1986-87	360.8	378.4	422.1	2322	2907	4020
1987-88	363.0	381.6	443.2	2341	2931	4221
1988-89	365.1	383.4	465.4	2347	2939	4432
1989-90	367.1	384.9	488.7	2351	2943	4654
1990-91	368.9	387.4	513.1	2365	2960	4886

Source: Exhibit HO-1, Table G-24; HO-SO-1; HO-SO-2; HO-PD-1; HO-PD-2

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 service of the decision, order or ruling of the Siting Council or within such further time as the Siting Council may allow upon request filed prior to the expiration of 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. (Sec. 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 Proposed Rulemaking Regarding Procedures for Licensing Certain Hydropower Projects Including Procedures for Small Conduit Projects)	EFSC 87-RM-100

FINAL DECISION AND ORDER

I. Background

On July 28, 1987, the Energy Facilities Siting Council ("Siting Council") issued a Notice of Proposed Rulemaking and Public Hearing regarding procedures for licensing certain hydropower projects including procedures for small conduit projects.

The Siting Council regulations pertaining to hydropower projects are contained in 980 CMR 11.00. The proposed regulations retain the language of the current regulations as published, with the exception of the insertion of the clause "pre-licensing conferences will not be held if inapplicable" to 980 CMR 11.04(7).

Pursuant to Chapter 595 of the Laws of 1985, 980 CMR 11.00 was amended in 1986. Due to insufficient notice prior to the publication of the 1986 amendments, it is necessary to consider the current regulations as published, as well as the proposed change to those regulations, as part of this rulemaking proceeding.

The 1986 amendments to 980 CMR 11.00 include five provisions. The first of the provisions exempts a certain class of small projects from certain Siting Council requirements. This exemption is contained in a new section, 980 CMR 11.04(5). Necessary definitions were added to clarify 980 CMR 11.04(5), and these definitions are contained in 980 CMR 11.01(6). The second provision adopts modular hydropower preliminary notification forms adaptable to separate project circumstances. This provision is included in 980 CMR 11.02(2). The third provision allows the Siting Council to review draft notification forms for completeness. This provision is included in 980 CMR 11.03(2) and 980 CMR 11.04(2). The fourth provision allows developers to elect whether or not the notification forms will serve as a notice of intent for local conservation commissions under G.L. c. 131, s. 40. This provision is included in 980 CMR 11.03(4) and 980 CMR 11.04(4). The final provision establishes developer and agency requirements and/or deadlines. This provision is included in 980 CMR 11.03(3), 980 CMR 11.03(5), 980 CMR 11.03(12), 980 CMR 11.04(3), and 980 CMR 11.04(6).

The Siting Council published the Notice of Proposed Rulemaking and Public Hearing in the Boston Globe, the Springfield Union News, and the Worcester Telegram and Gazette. The Notice of Proposed Rulemaking and Public Hearing and a copy of the proposed regulations were sent to all persons requesting a copy of the proposed regulations. In addition, the notice and a copy of the proposed regulations were delivered to the Regulations Division of the Office of the Secretary of State on July 31, 1987, and the notice was also sent to the Local Government Advisory Committee of the Massachusetts Municipalities Association and the Executive Office of Communities and Development on August 11, 1987.

On August 24, 1987 the Siting Council conducted a public hearing on the proposed rulemaking, during which no testimony was received regarding the proposed rulemaking. In addition, the Siting Council established August 31, 1987 as a deadline for submitting written comments on the proposed rulemaking. The Siting Council received no written comments on the proposed rulemaking.

II. Authority

The proceeding on the proposed rulemaking is conducted pursuant to G.L. c. 30A, s. 2 and G.L. c. 164, s. 69H.

III. Order

Accordingly, after hearing, review, and consideration, it is hereby

ORDERED That regulation 980 CMR 11.00 is hereby adopted effective the date of publication in the Massachusetts Register.

Frank P. Pozniak

Frank P. Pozniak, Esq.
Hearing Officer

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council by the members and designees present and voting: Sharon M. Pollard (Secretary of Energy Resources); Tim Gailey (for Paula W. Gold, Secretary of Consumer Affairs and Business Regulation); Elizabeth Kline (for James S. Hoyte, Secretary of Environmental Affairs); Dennis J. LaCroix (Public Gas Member); Joseph W. Joyce (Public Labor Member). Absent: Fred Hoskins (for Joseph D. Alviani, Secretary of Economic and Manpower Affairs); Stephen Umans (Public Electricity Member); Madeline Varitimos (Public Environmental Member).

Sharon M. Pollard

Sharon M. Pollard
Chairperson

14 September 1987
Date

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Boston Gas Company and Massachusetts LNG, Inc. for Approval of their Joint Third Long-Range Forecast of Gas Requirements and Resources	)	EFSC 86-25

FINAL DECISION

Frank P. Pozniak
Hearing Officer
September 10, 1987

On the Decision:

Brian G. Hoefler

TABLE OF CONTENTS

The Energy Facilities Siting Council hereby REJECTS the sendout forecast and the supply plan filed by Boston Gas Company and Massachusetts LNG, Inc. for the five years from 1986 through 1991.

I. INTRODUCTION

A. Description of the Company

Boston Gas Company ("Boston Gas" or "the Company") distributes and sells natural gas to residential, commercial, and industrial customers in the City of Boston and 73 other eastern and central Massachusetts communities. Boston Gas is the largest gas distribution company in the Commonwealth with about 500,000 customers and firm sendout of about 64,000 thousand dekatherms ("MDth")[1] during the 1985-86 split year. Boston Gas is the sole supplier of gas to the Wakefield Municipal Gas Company and exchanges gas with the Cambridge Division of Commonwealth Gas Company ("Commonwealth").

All of the Company's capital stock is held by Eastern Gas and Fuel Associates ("Eastern"). Algonquin Gas Transmission Company ("Algonquin" or "AGT") is Boston Gas' largest pipeline supplier. Tennessee Gas Pipeline Company ("Tennessee" or "TGP"), a division of Tenneco, Inc., also delivers supplies to Boston Gas. The Company's one subsidiary, Massachusetts LNG, Inc. ("Mass. LNG"), holds long-term leases on two liquefied natural gas ("LNG") storage facilities. Since Mass. LNG makes no wholesale or retail sales of gas, the sendout data provided in the forecast and the Energy Facilities Siting Council's ("Siting Council" or "EFSC") review of those data are exclusive to Boston Gas.

1/One MDth equals one billion Btus ("BBtu") or roughly one million cubic feet ("MMCF") of natural gas.

B. History of the Proceedings

On September 2, 1986, the Company filed its third long-range sendout forecast and supply plan. On September 15, 1986, the Hearing Officer issued the 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 October 6, 1986.

On October 20, 1986, the City of Boston ("City") and Distrigas of Massachusetts Corporation ("DOMAC") petitioned to intervene in the proceeding. On October 27, 1986, Boston Gas filed a response in opposition to the petition to intervene of DOMAC. On November 17, 1987, DOMAC filed a response to the Company's response to DOMAC's petition to intervene. On November 20, 1986, Boston Gas filed a motion to strike the response of DOMAC. On November 29, 1986, the Hearing Officer issued a Procedural Order denying the Company's motion to strike, and granting DOMAC's and the City's petitions to intervene in the proceeding.

On April 1, 1987, DOMAC filed a motion to withdraw as an intervenor from the proceeding. In a letter received on April 9, 1987, Boston Gas stated that it had no objection to the motion to withdraw. On April 21, 1987, the Hearing Officer issued a Procedural Order granting DOMAC's motion to withdraw from the proceeding.

The Siting Council Staff conducted eight days of hearings. The Company presented four witnesses: Jane P. Michalek, director of gas supply; Janet Walrod, supply analyst; Leo Silvestrini, manager of rates and economic analysis; and John Gilfeather, planning and design engineer. The Siting Council entered 112 exhibits into the record, largely composed of responses to information and record requests, and the City offered 24 exhibits into the record. The Company introduced three exhibits into the record, including its third long-range sendout forecast and supply plan and revised tables entered as Exhibit BGC-2.[2]

The City's briefs were filed on July 17 and August 5, 1987; the Company's briefs were filed on July 31 and August 10, 1987.

2/The Company filed revised tables on October 22 and November 19, 1986.

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. Berkshire Gas Company, EFSC 86-29, p. 2 (1987).

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. Berkshire Gas Company, EFSC 86-29, pp. 2-3 (1987); Boston Gas Company, et al., EFSC 84-25, p. 8 (1986).

B. Previous Sendout Forecast Conditions

In its previous review of Boston Gas' sendout forecast, the Siting Council approved the Company's sendout forecast subject to three conditions. In Condition One, the Siting Council ordered a comparison of the 1985-86 actual split year and peak day sendout growth with the growth forecast in 1985. Boston Gas Company, et al., EFSC 84-25, pp. 13, 19, 48 (1986). In Condition Two, the Siting Council ordered the Company to update its conservation and load management ("C&LM") studies including a report on when results from the Company's analyses would be ready for application in the Company's sendout forecast. Id., pp. 16-17, 48. In Condition Three, the Siting Council ordered the Company to undertake an extensive review of its sendout forecast methodology and supply planning process. Id., pp. 20-21, 49. As part of this review, the Company 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 results of, and conclusions from, this review were ordered to be included in the Company's 1987 filing (see Section IV, infra); an interim status report outlining the issues to be reviewed and a schedule for completing the review was to be included in the Company's 1986 filing. Id.

In addition, as Condition Nine, the Siting Council ordered Boston Gas to comply with the Siting Council's Order in Evaluation of Standards and Procedures for Reviewing Sendout Forecasts and Supply Plans of Natural Gas Utilities, 14 DOMSC 95 (1986),[3] and that Order's implementation in Administrative Bulletin 86-1. Boston Gas Company, et al., EFSC 84-25, pp. 46-48, 50 (1986).

Finally, as Condition Eleven, the Siting Council ordered Boston Gas representatives to meet with the Siting Council Staff within 30 days of issuance of that decision to discuss the scope and effort required to fulfill each condition. Id., p. 50. On July 15, 1986, representatives of Boston Gas met with the Siting Council Staff in compliance with Condition Eleven. Compliance with the remainder of the sendout forecast conditions is discussed in Sections II.C. through II.E., infra.

C. Weather Normalization and Planning Standards

As part of Condition Nine, Boston Gas was ordered to describe in detail and justify its methodologies for weather normalizing sendout data and for defining its design year and design day[4] planning

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3/In its Order in EFSC 85-64, the Siting Council established procedures which render its review of the 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, minimal-environmental-impact supply planning.

4/For the purposes of this proceeding, the Siting Council uses "design day" and "peak day" synonymously unless otherwise noted.

standards. Boston Gas Company, et al., EFSC 86-25, pp. 46, 50 (1986). For clarity in describing and analyzing these methodologies herein, the Siting Council also examines the Company's normal year planning standard since it is integrally linked to both the weather normalization process and the level of reliability achieved by the design year planning standard.

1. Description

a. Weather Normalization Process

Boston Gas normalizes its sendout data by applying a regression equation developed from the previous year's sendout data to normal year degree days ("DD"). The Company stated that this process "automatically" determines the Company's normalized sendout for the previous year (Exh. BGC-2, Sec. One, pp. 15-16; Tr. 1/14/87, p. 85).

b. Normal Year and Design Year Planning Standards

Boston Gas identified a number of factors which it considers in its normal and design year weather planning standards as well as some factors that it believes are not necessary to consider. The Company uses "the standard 'degree day' method to measure the heating demands that weather places on our system" (Exh. BGC-2, Sec. One, p. 16[5]). The Company asserted that the relationship between DD and sendout is influenced by the month in which the DD occur and by the pattern of DD over the previous few days (Exh. EFSC-33; see also Exh. EFSC-27). Boston Gas also stated its "opinion" that using effective degree days ("EDD"), a combined measure of temperature and wind effects, would not improve the Company's forecasting ability although the Company added

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5/See DPU 555-C, "Testimony and Exhibits of Charles P. Buckley," p. 3, referred to by Boston Gas in Exh. BGC-2 and in Tr. 1/14/87, p. 108. The Company stated that this document would provide a further explanation of "design year" and "peak day" (Exh. BGC-2, Sec. One, p. 16, Fn. 1). Accordingly, the Siting Council hereby takes administrative notice of this document, and it will be referred to hereinafter as "Mr. Buckley's Testimony."

that "supporting analysis cannot be located" (Exh. EFSC-33). Concerning weather trends over time, the Company stated that "there have been no identifiable temperature patterns, or cycles, over the past sixty years [i.e., 1923-1982]" (Mr. Buckley's Testimony, p. 6). When asked to provide documents and Company conclusions on general weather trends, Boston Gas stated that its "analyses are informal in nature and are not available in documented format" (Exh. EFSC-33).

To determine the proper level (i.e., number) and distribution of DD for normal and design year planning, Boston Gas used DD data recorded by the National Weather Service in the City of Boston (Exh. EFSC-31). The Company's weather analysis, known as the "Darling Weather Study," was conducted in 1974 by G.T. Darling, a Boston Gas employee[6] (Exhs. EFSC-31 and EFSC-32). The Darling Weather Study analyzed historical DD for Boston and determined the Company's normal and design year DD planning standards (Exh. EFSC-32).

The Darling Weather Study determined that the average annual DD for the period 1923-1973 is 5758 DD (id.). The Company set this DD level as its normal year planning standard in 1974 (id.).

For its design year planning standard, Boston Gas stated that it uses 6300 DD which "is a statistical determination, based on the 51 years from 1923-1973," adding that 6300 DD "has been determined by the Company's Management to be the weather target for facility and gas supply planning" (Exh. BGC-2, Table DD). Other documents in the record, however, indicate that the Company determined its design year to be 6300 DD in 1966 (Exhs. EFSC-32 and EFSC-35; Mr. Buckley's Testimony, p. 3). At that time the Company analyzed the previous 50 years of data to arrive at an expectation that 6300 DD would occur about once every 9.8 years[7] (Exh. EFSC-32). In 1974 the Company updated its calculation of

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6/A number of documents contained in the Darling Weather Study are dated as early as 1966 (Exh. EFSC-32).

7/The record provides conflicting evidence as to the actual time period studied to determine the 6300 DD design year standard. In Exh. EFSC-35, the Company asserted that the period 1929-1964 was studied. However, the Darling Weather Study contains statistics based on data back to 1915. Accordingly, the Siting Council assumes that at least 50 years of data were studied by the Company in determining its design year standard.

the probability of occurrence to once in 17 years based on the 51 years from 1923-1973 (Exh. BGC-2, Table DD; Mr. Buckley's Testimony). Boston Gas has not updated its normal or design year planning standards for data collected since 1973 (Exh. EFSC-33). However, the Company noted that weather occurring since 1973 has been on average warmer than normal (Mr. Buckley's Testimony, p. 5; see also Exh. BGC-2, Table DD).

The Company's weather data time period includes data collected in downtown Boston (1923-1935) and at Logan Airport (1936-1973) (Exhs. EFSC-29, EFSC-31, EFSC-32, and EFSC-36). Boston Gas stated its position that, even though data were collected both in downtown Boston and at Logan Airport, the Company "feels comfortable in using the 1923-1973 data as it stands" (Exh. EFSC-31). To support this position, the Company provided a statement from a 1949 United States Department of Commerce document suggesting that differences in weather recordings between the two locations "disappear in the averages" (Exh. EFSC-31). In addition, the Darling Weather Study included an internal memorandum dated April 7, 1966, which stated in part that a Boston Weather Bureau representative "expressed the opinion that there was no significant change in the seasonal degree days as a result of the change in the recording site" (Exh. EFSC-32).

In reference to cost implications associated with its choice of design planning standards, Ms. Michalek stated the Company's position:

> The Company is aware of the cost of being overconservative. How specifically we have done that, I really don't know. I think it's more or less in the minds of senior management that having sufficient supplies for design year as well as a design day is our department's number one priority. (Tr. 1/14/87, p. 128)

In follow-up to her assertion that Boston Gas is "aware of the cost of being overconservative," Ms. Michalek stated that she could not provide documented analysis supporting her assertion, but that "our analysis is discussions and several intangibles that are not documented" (Tr. 5/15/87, p. 115).

To distribute normal DD throughout the year, the Company allocated the 5758 DD to months based on the historical proportion of DD experience in each month (Exh. EFSC-35). Within each month, the Company factored in alternating cold and warm spells (Mr. Buckley's Testimony,

p. 4). Boston Gas expects a 65 DD day to be the coldest day in a normal year, a DD level taken from the American Gas Association's ("AGA") Gas Engineers Handbook, 1965 Edition (Exh. EFSC-34).

The distribution of 6300 DD for a design year is simply a 9.55-percent increase in normal year DD for each day, with adjustments for a design day of 73 DD and rounding effects (Exh. EFSC-35).

c. Design Day Planning Standard

Since at least 1966, Boston Gas has used a design day planning standard of 73 DD "which reflects the coldest recorded mean temperature ever to have occurred in the Boston area" (Mr. Buckley's Testimony, p. 4; Exh. COB-8). Ms. Michalek stated that this standard is a "management decision" and that "it's very unlikely that a minus eight day [i.e., 73 DD day] will occur; but since it did occur, we want to be prepared to meet it" (Tr. 1/14/87, pp. 126-127). The Company stated that the time period used to determine this "coldest recorded mean temperature" is 1923-1986 (Exh. BGC-2, Table DD). Although the Company acknowledged that data have been recorded as far back as 1872 (Exh. EFSC-32), Boston Gas has not indicated whether or not 73 DD was exceeded on any day prior to 1923.

Boston Gas has not studied the probability of a 73 DD day or colder occurring (Tr. 1/14/87, p. 105). The Company believes that more than 50 years of weather data would be required to determine the probability that a 73 DD day would occur (Exh. EFSC-36). Nevertheless, Ms. Michalek stated that, "If there is one chance that it could occur out of a hundred, we have to plan for that" (Tr. 1/5/87, p. 131). Ms. Michalek also indicated that Boston Gas has not studied the incremental cost of its 73 DD design day planning standard and that, "although the Company works within the bounds of least cost supply planning, reliability does take precedence over that" (Tr. 1/14/87, pp. 125-127).

2. Analysis

In determining the adequacy of the Company's weather normalization process and planning standards as required in Condition

Nine, the Siting Council examines the assumptions and methodologies used to establish that process and those standards.

a. Consideration of Effective Degree Days

As a basic assumption, Boston Gas used DD to correlate sendout data with weather data. Rather than providing analysis in support of such an assumption, Boston Gas simply asserted that, "Since weather is the predominant force behind heating sendout, temperature (Logan degree days) is the principal explanatory variable" (Exh. BGC-2, Sec. One, p. 17). When asked about the possibility of improving this correlation by use of EDD, Boston Gas offerred its "opinion" that EDD do not provide a better correlation with sendout data than do DD -- an opinion that the Company could not support with any analysis (Exh. EFSC-33).

The Siting Council rejects the Company's opinion as unsubstantiated and finds the Company's weather analysis to be deficient for failing to adequately consider the use of EDD as a method for improving sendout correlation with weather. Accordingly, the Siting Council finds that the Company has failed to establish that its method for selecting DD is appropriate or reliable.

b. Range of Weather Data

In establishing its normal and design year planning standards, Boston Gas selected a range of weather data from 1923-1973. The Siting Council addresses a number of issues raised by the record in this proceeding concerning the methodology used to select this range of weather data.

Boston Gas claimed there are no discernable weather trends over time, a claim which the Company could not support with documentation. At the same time, however, Boston Gas noted that the Blue Hills Observatory (a site used consistently for weather data collection, and whose historical data series was not interrupted by a relocated weather station) has recorded fewer DD in the period since 1936 than in the period prior to 1936, which reflects the same pattern as the Company's weather database (Exh. EFSC-36). In addition, Ms. Michalek stated, "We know that the degree days are getting fewer as we get closer and closer to 1986; however, we still feel confident that the '23 to 1973 period accurately reflects what we can expect to see" (Tr. 5/6/87, p. 46). While the Company has stated that there are no identifiable temperature patterns, or cycles in the time period covered by the Company's weather database, the Company's own evidence indicates the clear possibility of discernable weather trends. Therefore, the Siting Council rejects the Company's claim that there are no identifiable weather patterns over time.

Boston Gas based its planning standards on data collected in part in downtown Boston (1923-1935) and in part at Logan Airport (1936-1973). The Company, however, has failed to show that weather data collected prior to 1936 in downtown Boston are consistent with data collected beginning in 1936 at Logan Airport.[8] When asked to provide any statistical analyses supporting its assertion that the pre-1936 data remain valid today, the Company stated that it had no such evidence, and could only provide a vague 1949 Department of Commerce statement and an internal memorandum noting a Boston Weather Bureau employee's opinion (Exh. EFSC-31). These two documents are not persuasive and cannot be accepted by the Siting Council as adequate data analyses.

When provided with an analysis indicating that differences between the pre-1936 and post-1936 data are statistically significant, Boston Gas, while agreeing that the statistics indicate significant differences in the two datasets, responded that (1) the difference may not be due to the relocation of the weather data collection point, and (2) that "There is no evidence to suggest that weather data collected before January 1, 1936 is no longer representative of the weather that can occur in this region" (Exh. EFSC-36). Based on its response, Boston Gas apparently disregards the meaning of significant statistical tests, as well as the occurrence prior to 1936 of 100 percent of the days 70 DD or colder, 86 percent of the days 65 DD or colder, and 75 percent of the

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8/The Siting Council notes that the Company witness currently responsible for sendout analysis and supply planning was not aware that the Company's weather data had been collected at two different locations (Tr. 1/14/87, pp. 101-105).

days 60 DD or colder[9] (Exh. EFSC-36).

While the Siting Council agrees that the relocation of the Boston weather station may not be the only, or even the primary, cause of changes in Boston weather data over time, the statistical indications are too strong to be summarily ignored. Therefore, the Siting Council finds that the Company has 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.

Another issue regarding the Company's range of weather data is that Boston Gas does not update its normal and design year planning standards for weather data collected since 1973.[10] Accepting the premise that weather data do not change over time, such a practice would be reasonable. However, without evidence that weather patterns are constant over the years, Boston Gas' approach fails to avoid the risk of undetected changes in its weather database. Thus, the Siting Council finds that Boston Gas has failed to adequately maintain its normal and design year DD planning levels by updating the weather database.

Based on the foregoing, the Siting Council finds that the Company's methodology for selecting its range of weather data is neither appropriate nor reliable.

c. Weather Normalization Process

Based on the record, the Siting Council finds that the Company's weather normalization process -- applying a regression equation developed from a year's sendout data to normal year weather data -- is reviewable, appropriate, and reliable.

9/These statistics were based on the time period 1880-1985 (Exh. EFSC-36).

10/Boston Gas' design day standard is based on the time period 1923-1986 (Exh. BGC-2, Table DD).

d. Normal Year Planning Standard

The Siting Council finds 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 -- is reviewable and appropriate. The one obvious weakness in this methodology is the Company's selection, based on a 1965 AGA engineering handbook, of 65 DD as the coldest day in a normal year. Although this weakness is not fatal to the integrity of the normal year determination methodology, Boston Gas should be capable of stronger analysis in support of its determination of the coldest day in a normal year.

Weaknesses in input data assumptions, however, are fatal to the integrity of the Company's normal year standard. The Siting Council found in Section II.C.2.a, supra, that the Company's process for selecting DD as the primary weather indicator, and thus the primary factor in the Company's normal year determination, is neither appropriate nor reliable. In addition, the Siting Council found in Section II.C.2.b, supra, that the Company's methodology for determining its range of weather data is inappropriate and unreliable. Since these weather data are used to determine total normal year DD and to allocate DD to each month within the normal year, the normal year standard is based on inappropriate and unreliable data.

Accordingly, the Siting Council finds that the Company has failed to establish its normal year planning standard is reliable.

e. Design Year Planning Standard

In reviewing the Company's design year standard, the Siting Council examines the information the Company relied on in setting and maintaining that standard.

The Company asserted that its 6300 DD design year planning standard is a "statistical determination" yet at the same time stated that 6300 DD had been set by Company management. The record in this proceeding shows that the 6300 DD standard was selected as the design year in 1966 by Company management and that the associated statistics presented in the 1986 Forecast were calculated in 1974 using 6300 DD only as a premise. Therefore, the Siting Council rejects the Company's assertion that 6300 DD is a statistical determination and accepts that the standard was judgmentally set by Company management.

While a company's judgment may be the only way to set such a planning standard, a company must have as much information at its disposal as is appropriate and reasonably possible when making such a decision. The only information that the record indicates was available when the standard was set in 1966 is the calculation of probabilities of various DD levels occurring -- in the case of 6300 DD, once every 9.8 years.[11] In 1974, the Company recalculated the probability of occurrence at once every 17 years. Boston Gas observed that years subsequent to 1973 were warmer than normal. A reasonable conclusion based on that observation would be that the probability of a 6300 DD occurring has decreased since 1973 and stands today at some probability of occurrence more remote than once every 17 years.

Boston Gas has chosen to ignore the reliability drift (in terms of probability of occurrence) of its design year planning standard caused by increasingly warmer weather over time. Clearly the 6300 DD standard has been set as a benchmark rather than as a level of reliability; that is, DD determines reliability rather than reliability determining DD. The result is a standard which has become substantially more conservative than originally set. Thus, the Siting Council finds that the Company has failed to establish that it manages the level of reliability maintained by such standard.

The largest gas companies in the Commonwealth must consider an additional dimension of the design year planning standard -- the effects on supply costs as reliability levels are adjusted. Boston Gas provided

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11/In Exh. EFSC-32, the Company indicated that two statistics were available to Boston Gas Staff in 1966 -- one based on the previous 50 years of data indicating an occurrence probability of once every 9.8 years, and one based on the previous 40 years of data indicating an occurrence probability of once every 12.9 years. For consistency with later calculations, the Siting Council will use the statistics based on 50 years of data.

no information showing how the Company considered the cost/reliability tradeoffs necessary to maintain a design year reliability standard of 6300 DD, as compared to a higher or lower standard, other than the statement that the Company is "aware of the cost of being overconservative" which is substantiated only by "discussions and several intangibles that are nor documented." Therefore, the Siting Council finds that Boston Gas failed to adequately consider cost/reliability tradeoffs in setting its design year planning standard.

Accordingly, the Siting Council finds that the Company has failed to establish that the methodology used to determine its design year planning standard is appropriate.

f. Design Day Planning Standard

Like the design year planning standard, the design day planning standard is, to a large extent, based upon company judgment and therefore not easily evaluated. Thus, the Siting Council examines the information available to Boston Gas in setting and maintaining its design day standard at 73 DD.

The only information clearly used by Boston Gas was that 73 DD is the coldest day to have occurred since 1923. Despite repeated inquiries, the Company provided no information indicating a reasonable grasp of the level of reliability this standard provides[12] (Exhs.

12/The Siting Council notes the difference in the Company's expectations of the occurrence frequency of a 73 DD design day and the occurrence frequency of a 6588 DD "severe year" as described in Appendix B of Exh. BGC-2.

The Company's weather data indicated that a 73 DD day occurred once in 1934 (Exh. EFSC-36). Mr. Buckley's Testimony noted that the 73 DD day was the coldest day ever recorded in Boston weather history which began in 1870 (Mr. Buckley's Testimony, p. 4; Exh. EFSC-31). Based on this occurrence, the Company concluded that it must plan for a 73 DD day (Exh. BGC-2, Table DD).

The Company's weather data also indicated that, on a November through October split-year basis, 6588 DD or more occurred twice since 1920 -- in 1933-34 and 1939-40 (Exh. EFSC-36). In addition, the Darling Weather Study indicated that 6588 DD was exceeded, on a July through June basis, four more times prior to 1920. However, despite these occurrences, the Company does not expect a severe year to occur (Exh. EFSC-19; Tr. 1/5/87, p. 52).

The difference in logic applied to these two situations is perplexing.

EFSC-32, EFSC-34, and BGC-1; Tr. 1/14/87, pp. 105-106). In addition, Boston Gas provided no information or documentation showing how the Company considered the cost/reliability tradeoffs necessary to maintain a reliability standard of 73 DD, as compared to a higher or lower standard (Tr. 1/14/87, pp. 125-128). Therefore, the Siting Council rejects the Company's assertion that it works within the bounds of least-cost planning.

Based on the record, the Siting Council finds that Boston Gas has not shown 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. Accordingly, the Siting Council finds that the Company has failed to establish that the methodology used to determine its design day planning standard is appropriate.

3. Conclusions

Boston Gas has demonstrated that its weather normalization methodology is reviewable, appropriate, and reliable. However, the Company has failed to establish (1) that its normal year planning standard is reliable, (2) that the methodology used to determine its design year planning standard is appropriate, and (3) that the methodology used to determine its design day planning standard is appropriate.

Accordingly, the Siting Council finds that Boston Gas has complied with that part of Condition Nine requiring the Company to explain in detail and justify its weather normalization process, but has not complied with that part of Condition Nine requiring the Company to justify its selection of its design year and design day planning standards.

D. Forecast of Annual Requirements

1. Description

a. New Forecast Methodology

In its 1986 Forecast, Boston Gas presented for the first time its new sendout forecasting methodology. The Company asserted that this methodology focuses on, "first, forecasting territory-wide market demand; second, establishing marketing policies which will allow it to maximize the penetration of that demand; third, analyzing the aggregate sendout demand by existing customers; and fourth, assessing the supplies available to meet the sendout demand" (Exh. BGC-2, Intro., p. 2). The Company "believes this demand-oriented approach is necessary because the gas industry in New England is changing from one that is supply-driven to one that is demand-driven" (id., p. 3).

In this section, the Siting Council evaluates the first three steps of the Company's new methodolgy. The fourth step of the new methodology, the assessment of supplies available to meet sendout, will be evaluated in Section III, infra. The results of the sendout forecast are summarized in Table 1.

b. Interim Market Simulation Model

Boston Gas' plans for the first step of its new sendout forecasting methodology include development of a market simulation model to analyze and forecast potential service territory demand (Exh. BGC-2, Sec. One, p. 1). Since this model is still in the development stages, however, Boston Gas filed an "interim" market simulation model ("interim model") based on the general concepts and relationships being developed for the full model[13] (id.). Using this interim model, the Company

13/The only step in the new methodology that the Company indicated is not yet complete is the market simulation model. The Siting Council assumes that the Company's marketing policies and regression model are basically in their final format.

forecasted potential market demand over the five-year forecast period.

The interim model divided aggregate demand into the Company-designated major market segments of individually metered residential customers, master-metered apartment house customers, and commercial/industrial ("C/I") customers. Boston Gas further disaggregated each of these three classes into demand by existing buildings and dwelling units in the base year of 1985-86[14] ("base year") and new demand due to increased economic expansion in future years (id., pp. 2-3).

i. Demographic Factors

Boston Gas identified key demographic factors driving energy demand in each market sector. Those factors were employment in the C/I sector, and population and dwelling units in both the residential and apartment house sectors (id., p. 2). The Company did not forecast population and dwelling units for the 1986 filing, but rather assumed that residential and apartment house demand would follow the same trend as employment increases (id., p. 3). To support this assumption, the Company reasoned that changes in employment translate into migration resulting in changes in number of households and therefore in residential and apartment house demand (Exh. EFSC-67).

The base-year employment data were derived from the Massachusetts Division of Employment Security as collected by Arthur D. Little, Inc. ("ADL") (Exh. EFSC-67). The Company did not indicate how it forecasted future employment data.

14/Mr. Silvestrini testified that Boston Gas used a base year of 1984 in its forecast (Tr. 5/7/87, pp. 8-9). The Company's forecast filing, however, stated that 1985-86 data were used for the base year, and contained no information indicating that 1984 data were used for the base year (Exh. BGC-2, Sec. One, pp. 2-7). The Siting Council assumes that 1985-86 data were used for the base year.

ii. Residential Class

The Company divided its forecast of residential demand into demand of existing customers and demand of future customers.

To determine demand of existing residential customers, Boston Gas first determined their demand for the base year then forecasted their future demand by adjusting base-year demand to reflect conservation impacts. Boston Gas assumed conservation rates would be 1.2 percent per year through 1989 and 0.8 percent per year thereafter (Exh. BGC-2, Sec. One, p. 7). These conservation rates were assumed "to facilitate the generation of this [i.e., the 1986] forecast" (id.), and were based on estimates provided by ADL of the effects of replacing appliance stock with more efficient equipment (Exh. EFSC-67). Other changes to existing residential customer sendout included non-heating to heating conversions which Boston Gas believes depend on market demand and marketing policies (Exh. BGC-2, Sec. One, p. 7).

Next, Boston Gas forecasted new residential demand by assuming that gas would capture a certain market share (i.e., 33 percent) of total new residential energy demand. Total new residential energy demand was calculated for the base year and scaled up for future years based on employment level (id.). Boston Gas justified its assumption that gas would continue to capture its traditional 33 percent market share by stating, "Absent any better forecasting information, historical performance is a generally accepted proxy for future performance" (Exh. EFSC-67).

iii. Apartment House Class

Like the interim residential model, the interim model for existing apartment houses first determined base year demand for existing customers and then forecasted changes in existing customers' demand. Based on ADL estimates, the Company assumed that conservation by existing customers in future years would reduce sendout by 1.2 percent per year through 1990 and 1.0 percent per year thereafter (Exh. BGC-2, Sec. One, p. 6; Exh. EFSC-67). The interim model did not forecast apartment house non-heating to heating conversions although Mr.

Silvestrini stated that including such a forecast is "probably something that we will incorporate at some point in time" (Tr. 5/7/87, p. 21).

To forecast new apartment house demand, Boston Gas calculated the apartment house share of new energy demand in the base year which was assumed to be 36 percent, the same as it has been in recent years (Exh. BGC-2, Sec. One, p. 6). New apartment house demand in future years was scaled up for changes in employment over the forecast period (id., pp. 3, 6).

iv. Commercial/Industrial Class

The Company forecasted existing C/I demand by estimating the base year average energy use per employee by fuel type then adjusting in future years for (1) customers' response to price changes, (2) conservation penetration, and (3) fuel switching (Exh. BGC-2, Sec. One, p. 4). ADL estimated short-term price elasticities at -0.2 in the commercial sector and -0.3 in the industrial sector (id.; Exh. EFSC-67). Conservation rates were assumed to be 1.3 percent in the first year and 1.0 percent in each year thereafter (Tr. 5/7/87, p. 23). Boston Gas identified the three primary categories of fuel switching by existing customers as dual-fuel customers, non-dual-fuel customers who replace traditional equipment, and non-dual-fuel customers who install new equipment in non-traditional markets (e.g., gas cogeneration, gas air conditioning) (Exh. BGC-2, Sec. One, p. 4).

The forecast of new C/I customers was based on first forecasting total new C/I energy demand and then determining the market share for gas. New C/I energy demand was based on energy use per employee and projections of new employment. Based on ADL estimates and Company adjustments to those estimates, Boston Gas assumed in the interim model that future energy use per employee would be 85 percent of existing energy use per employee (id., p. 5; Exh. EFSC-67). To determine the gas market share of total new energy demand, Boston Gas assumed gas would continue to capture the same market share that it had captured in the past for all categories except C/I heating and water heating markets (Exh. BGC-2, Sec. One, p. 5). The Company reasoned that, in markets other than heating and water heating, the ability to interchange fuels is limited by the specific end-use (Exh. EFSC-67). Thus, without any more specific data, historical performance is the best indicator of future demand (id.). In the heating and water heating markets, the Company (1) projected the type of equipment that will be installed, (2) determined the feasibility of using a particular type of fuel for each type of equipment, (3) estimated life-cycle costs of each fuel-equipment combination, and (4) reviewed the ability of the existing distribution system to absorb growth in anticipated growth areas (Exh. BGC-2, Sec. One, pp. 5-6).

c. Load Growth: Marketing Policies

Based on the marketing opportunities identified in the interim model, Boston Gas targeted specific growth sectors through a marketing strategy that "maximizes the benefits of load growth to the customers and the Company, while maintaining an adequate level of reliability" (Exh. BGC-2, Sec. One, Summary and p. 8). This second step in the Company's new sendout forecasting methodology took into account both market demand and marketing policies to forecast gross load additions and net load gain for each of the next five years (id., pp. 13-14).

The Company determined the benefits of each market segment by assessing, (1) the overall size of the market, (2) the ease with which the load can be physically added, (3) the cost of adding the load, and (4) the projected return on the investment required to hook-up the load (id., p. 8). The Company also stated that it adds only such load as does not increase prices to existing customers (Exh. EFSC-68).

Boston Gas asserted that its demand research indicates that the C/I and apartment house markets provide the largest market potential (Exh. BGC-2, Sec. One, p. 9), and that the C/I market offers "the greatest potential for ease and cost of the hook-up and return on investment" (id.).

In its evaluation of the cost of connecting new load and the return on such investment, the Company first determined whether a market sector could be met with existing and potential supplies by considering the load profile of that market sector (Exh. EFSC-68). Since Boston Gas has neither load duration curves nor peak load data for its customer classes, the Company evaluated supply adequacy based on monthly data divided into heating and non-heating load (id.). Mr. Silvestrini justified this approach by noting that "The marginal cost of adding customers is really a function of a seasonal peak.... Marginal peak day costs are not that relevent" (Tr. 5/7/87, p. 25). The Company used a simple payback calculation to determine that the residential conversion market yields the quickest recovery of investment costs at 0.5 year while the C/I and apartment house sectors yield recovery periods of 0.6 year (id.). However, the Company added that when the addition of residential heating load is balanced against the increase in supplemental supplies necessary to serve that load, the C/I and apartment house markets "result in the lowest retail rates to existing customers" (id.).

Boston Gas has adopted a strategy "which targets principally the commercial/industrial sector, and has designated the residential sector, within certain bounds, as the 'swing market'" (Exh. BGC-2, Sec. One, p. 8). Boston Gas believes that the C/I sector provides the best opportunity for meeting Company load growth objectives with fewer installations and lower capital investment (id., p. 10).[15] The Company expects 70 percent of gross load additions and 82 percent of net load additions over the forecast period to occur in the C/I and apartment house markets (id., p. 9).

The residential heating market consists mainly of non-heating to heating conversion customers although there exists a small market of new and existing residences that currently have no gas service (id., pp. 10-12). The conversion customers serve as the swing market by helping to offset demand variability in the C/I market "thereby maintaining relatively stable overall growth targets from year to year, as well as

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15/Although Boston Gas divided its market into residential customers, apartment house customers, and C/I customers because those are "classes which pose distinct marketing characteristics and challenges" (Exh. BGC-2, Sec. One, p. 2), the Company did not clearly distinguish among those three sectors in describing its marketing policies. Instead, the Company distinguished among C/I, residential heating, and residential non-heating customers (id., pp. 8-13). Apparently, the Company consolidated apartment house marketing policies with C/I policies (id.).

balance heating/non-heating load additions" (id., p. 12). The Company has estimated total conversion potential in its service area to be about 30,000 to 40,000 units, but, due to economic constraints and administrative limits, the Company forecasted the addition of 3,000 to 4,000 conversion customers per year (id., p. 11). Boston Gas expects the residential non-heating market to attain its growth from conversions of water heaters from oil to gas and from new customers (id., p. 13).

d. Existing Sendout: Regression Model

To analyze existing aggregate sendout, the third step in the new sendout forecasting methodology, the Company developed a model consisting of an ordinary least squares ("OLS") regression equation of the previous year's daily heating sendout, aggregate baseload, and a cold snap factor ("regression model") (Exh. BGC-2, Sec. One, pp. 15-19). The regression equation and certain explanatory statistics are summarized in Table 2.

To estimate the regression equation, Boston Gas first separated baseload from total load to determine heating load (id., p. 16). For its estimate of baseload, the Company used average consumption data for July and August which Ms. Michalek termed the Company's "most conservative" estimate (id.; Tr. 1/14/87, p. 78). Next, a multiple regression equation was fitted to heating sendout (Exh. BGC-2, Sec. One, p. 17). The Company selected the following variables for that equation to achieve a strong R^2 statistic: a DD variable; and dichotomous variables for each ten-DD span, for the months October through May, and for periods of two and three consecutive cold days (Exh. BGC-2, Sec. One, p. 17; Exh. EFSC-27; Tr. 1/14/87, pp. 67-74). The Company's only justification for selecting these particular variables was that, based on "the discretion of the person that is designing the model," those variables provide a strong correlation with sendout (Tr. 1/14/87, p. 74).

Boston Gas asserted that, "Collectively, this regression equation is highly representative of the Company's heating sendout," and that "The criteria on which a regression model should be evaluated indicate a good fit" (Exh. BGC-2, Sec. One, pp. 17-18). To substantiate these claims, the Company provided an R^2 statistic indicating that approximately 98 percent of the variation in heating sendout is explained by the regression equation, and stated that the "error factor ... appears random for the most part" (id., p. 18). The Company warned that the number of explanatory variables might have provided a misleadingly high R^2 value but that "the measure is sufficiently high to be considered a valid statistic" (id.).

The Company used a single year of sendout data (split-year 1985-86) to estimate the regression equation (Tr. 1/14/87, p. 78). Ms. Walrod stated that additional years of data were excluded because of changes in the customer base over time and lack of data to capture those changes (id., pp. 79, 82). She also stated her opinion that adding more years of data would not help improve prediction on colder days where the Company believes the model tends to consistently underpredict requirements (id., pp. 94-95; Exh. BGC-2, Sec. One, p. 18).

Ms. Walrod testified at length about whether the Company's model specification conforms with certain OLS assumptions. Concerning autocorrelation, Ms. Walrod asserted that, "I am sure that our sendouts are autocorrelated.... It would affect how well the model appears to fit the data ... but the coefficients would pretty much remain the same" (Tr. 1/14/87, p. 66). She added that an autocorrelation correction "may possibly make the confidence interval wider, which is not as statistically acceptable" (id., p. 90). The Company provided a Durbin-Watson statistic for the equation (see Table 2) which did not conclusively indicate whether or not an autocorrelation correction should have been made (Exh. EFSC-30). Concerning multicollinearity, Ms. Walrod asserted that the nature of dichotomous variables "will eliminate a lot of the multicollinearity" (Tr. 1/14/87, p. 67). She added that, "as far as the multicollinearity problem, we haven't really concerned ourselves all that much with it, because it [i.e., the regression model] better describes our sendout than" the previous model did (id., p. 74). In reference to the independence of error terms, Ms. Walrod stated that she had detected "no real pattern" to the error terms (id., pp. 75-76). Other explanatory statistics are summarized in Table 2.

For cold weather forecasts, the Company applied two types of sendout adjustments. First, the two and three consecutive-cold-day variables become active in the regression equation on days of 35 DD or more when the previous day and two previous days, respectively, were colder than the current day (id., pp. 87-88; Exh. BGC-2, Sec. One, p. 17). The logic for this particular scheme was never clearly explained, although the Company provided that one justification for increasing the sendout forecast at the 35 DD threshold is that use of supplemental supplies becomes necessary at about 35 DD, and "The Company wants to make sure that it has the capacity available, propane and L.N.G. capacity to meet sendout" (Tr. 1/14/87, p. 111).

Second, the Company added a four percent "cold snap factor" to both existing and new heating load on days of 40 DD or more in the design sendout equation[16] because tests of the equation during two periods of extreme weather indicated consistent underprediction in such weather by 3.5 to 4.5 percent (id., pp. 94, 124; Exh. BGC-2, Sec. One, pp. 18-19; Exh. EFSC-27). Ms. Michalek explained that "the regression model without the four percent predicts predictable customer behavior; whereas, that additional four percent is our attempt to quantify unpredictable customer behavior" adding that "we think that predicting that customers will use more on a given day is the best possible route to assure that we always have sufficient supplies" (Tr. 1/14/87, p. 94).

In response to questioning about the causes of the consistent underprediction in cold weather, Ms. Walrod stated that underprediction is probably caused by trying to apply a linear relationship to non-linear data (id., p. 89). She does not believe that specifying different independent variables or including more years of data would significantly improve the forecast (id., pp. 91-95).

e. Forecast of Normal and Design Year Requirements

To determine normal year requirements, the Company applied normal year DD in the regression equation (without the four percent cold snap factor) and added baseload to determine daily sendout for the base year (Exh. BGC-2, Sec. One, p. 19). Next, normal year requirements were forecast over the five-year forecast period by adjusting the base year

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16/The differences between the Company's normal and design models are described in the Section II.D.1.e, infra.

sendout for gross load additions and projected load losses as determined by the interim model and marketing policies (id., p. 13).

The Company used a slightly different methodology to determine design year sendout requirements. The differences are (1) using design DD in the regression equation, (2) applying the four percent cold snap factor to all days with 40 DD or more, (3) adding all load growth for the year prior to the beginning of the heating season on November 1, and (4) assuming no conservation, load losses, or attrition occurs during the year that is being forecasted[17] (id., p. 19; Tr. 1/14/87, pp. 119-120, 144-145; Tr. 5/7/87, pp. 42-45).

The results of these two forecasts are summarized in Table 1.

2. Analysis

a. Previous Conditions

In response to Condition One of the Siting Council's previous decision, Boston Gas filed an analysis of its 1985-86 normal year load growth (Exh. BGC-2, Appendix A, Response to Condition One). In that analysis the Company indicated that it forecasted 1985-86 normal year load growth to be 2500 MMCF yet the load growth experienced was only 766 MMCF. The Company attributed the 1356 MMCF difference to fuel switching (50 MMCF), "conservation/load loss/attrition" (1000 MMCF), and timing of new load additions (306 MMCF). Since Condition One required the Company to compare actual growth with that forecasted, the Siting Council finds that Boston Gas has complied with that portion of Condition One relating to the 1985-86 normal year load growth.

The Company was ordered in Condition Two to update its C&LM studies and provide an estimate of when the results would be ready for

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17/The Company assumed that no load reduction occurs during the year being forecast but assumed that load reduction did occur in the previous year. For example, the forecast of design requirements for 1987-88 assumed no load reduction during 1987-88 but accounted for load reduction projected during 1986-87; the forecast for 1988-89 assumed no load reduction during 1988-89 but accounted for load reduction projected during 1987-88; etc.

application in the Company's forecast. The Company filed updates on its meter-reading study, database reports, and 1986 appliance saturation survey, but failed to indicate when results from its studies would be ready for application in its sendout forecast (id., Response to Condition Two). Accordingly, the Siting Council finds that Boston Gas failed to comply with Condition Two.

In Condition Three, the Siting Council ordered the Company to undertake an extensive review of its forecast methodology and supply planning process to be completed for the Company's 1987 filing. In the interim, the Company was ordered to file as part of its 1986 forecast a status report on compliance with this condition outlining all the issues to be studied and the schedule for completing the evaluation.

The Company's status report in its 1986 filing included neither an outline of issues to be studied nor a schedule for completing the evaluation (Exh. BGC-2, Appendix A, Response to Condition Three). Ms. Michalek stated that the outline of issues and a schedule for completing the evaluation were not yet available; most of the Company's planning takes place during the period September through January thereby delaying any progress toward completing the condition until April 1, 1987, "basically because we are busy doing our jobs until that time"[18] (Tr. 1/5/87, pp. 126-128). Ms. Michalek's comments contrast with her memorandum filed in response to Condition Eleven stating the Company's intention of meeting at least part of the status report requirements in the 1986 filing (Exh. BGC-2, Appendix A, Response to Condition Eleven).

The Siting Council finds that Boston Gas has not sufficiently justified its failure to file a status report on its plans for complying with Condition Three. Accordingly, the Siting Council finds that Boston Gas has failed to comply with that part of Condition Three pertaining to filing a status report along with Company's 1986 forecast.

As part of Condition Nine, the Siting Council ordered Boston Gas to report on the accuracy of its past forecasts. In response, Boston Gas filed Table FA which compares the Company's past forecast with the actual normalized sendout for those years (Exh. BGC-2, Table FA).

18/As of the close of the record in this proceeding on July 1, 1987, Boston Gas had not provided the status report.

Accordingly, the Siting Council finds that Boston Gas has complied with that portion of Condition Nine pertaining to forecast accuracy.

In Condition Nine, the Siting Council also ordered the Company to prepare its sendout forecast and supply plan based on a new split year beginning November 1 and ending October 31. Since the Company filed its 1986 forecast based on the new split year, the Siting Council finds that Boston Gas has complied with that portion of Condition Nine pertaining to the new split year.

b. Normal Year and Design Year Methodology

i. Interim Market Simulation Model

The Company is in the midst of developing a new model based on end-use characteristics (Exh. EFSC-65). Model development was not complete at the time of the 1986 filing. As a result, the Company filed a forecast based on a "more aggregated" interim model (Exh. EFSC-67). While using a more aggregated model sounds like a reasonable transition methodology, in practice, the Company's interim model relied heavily on broad simplifying assumptions to "facilitate" preparation of the 1986 forecast (see Exh. BGC-2, Sec. One, pp. 2-7). For example, since Boston Gas had no forecasts of population and dwelling units -- the two basic factors identified by the Company for determining residential and apartment house demand -- the Company assumed that such demand would follow the same trend as the employment increases used to forecast C/I demand because changes in employment were believed to flow through to changes in population and dwelling units. The Company also assumed that almost all demand in the three sectors would continue to achieve the same market share for the next five years as they had achieved in recent years, since, "Absent any better forecasting information, historical performance is a generally accepted proxy for future performance."

For large gas companies like Boston Gas, the Siting Council cannot accept such broad assumptions as substitutes for reasoned analysis. While there may be some justification for making these particular assumptions on an interim basis, it does not follow that the assumptions will result in a reliable forecast. Thus, the Siting

Council finds that the Company has failed to establish that its interim model for forecasting territory-wide market demand is an appropriate input to its determination of sendout requirements.

We acknowledge, however, that end-use models, if implemented properly, can be effective methods for forecasting market demand.

ii. Load Growth: Marketing Policies

The Company's marketing policies for "maximizing the penetration" of demand are based directly on the marketing opportunities identified in the interim model. Since the Siting Council found in Section II.D.2.b.i, supra, that the Company's interim model for identifying marketing opportunities is not appropriate, the Siting Council also finds that Boston Gas has failed to establish that its marketing policies based on those opportunities reliably predict gross load additions and net load gain.

iii. Existing Sendout: Regression Model

The Company's specification of its regression model contains numerous inadequacies. To begin with, the Company used its "most conservative" estimate of baseload to determine heating sendout requirements resulting in a "worst case" estimate of the proportion of total sendout attributed to heating sendout (Tr. 1/14/87, pp. 76-77). This methodology clearly overstates temperature-sensitive sendout.

Next, the Company did not use a systematic method for selecting and evaluating the variables in the regression equation. Simply checking for improvement in R^2 and relying on "the discretion of the person designing the model" does not constitute sound analysis.

Third, the Company ignored key ordinary least squares regression assumptions. The Company's witness testified that she was "sure that our sendouts are autocorrelated" adding that autocorrelation corrections would widen the prediction confidence interval "which is not as statistically acceptable." In fact, correcting autocorrelated data -- that is, providing truer predictions and stronger summary statistics -- is more statistically acceptable. In addition, the Company has not concerned itself with another potential violation of an OLS assumption: multicollinearity. Further, the Company's assertion, without any supporting analysis, that there is no real pattern to the error terms is weak.

Fourth, the Company added the two and three consecutive cold day variables into the equation based on a management decision without analytical justification. The correlation between these two variables and sendout is extremely weak (see Table 2), a point acknowledged by the Company (Tr. 1/14/87, p. 85). Yet the Company still included these variables in its model as a method for ensuring that there is adequate propane and LNG to meet requirements. In fact, without statistical validation, these two variables contribute to an overstatement of propane and LNG requirements.

Fifth, the Company tried to capture the effects of "unpredictable customer behavior" by adding a cold snap factor of four percent to all days of 40 DD or more. The unpredictable customer behavior was detected by analyzing sendout data from periods of extreme weather that occurred during the winter of 1980-81 and January 1982 -- that is, by applying winter 1980-81 and January 1982 conditions to a regression equation estimated from 1985-86 data. In view of the Company's decision to use only one year of sendout data to estimate its regression equation because of changes in its customer base over time -- changes the Company has not been able to quantify -- the justification for the cold snap factor is clearly faulty.

Finally, the Company's witness identified the most likely cause of underprediction in cold weather as an attempt to fit a linear relationship to non-linear data, yet Boston Gas provided no evidence indicating that it considered methods to account for data non-linearity. Rather, the Company categorized such underprediction as "unpredictable customer behavior" and applied a four percent cold snap factor, another faulty justification for that factor.

Given these statistical and analytical inadequacies, the Siting Council rejects as unsubstantiated the Company's assertions that (1) the regression equation is highly representative of the Company's heating sendout and (2) the criteria on which a regression model should be evaluated indicate a good fit.

In contrast to these assertions, at least three of the steps in specifying the regression model -- baseload, two and three consecutive cold day parameters, and cold snap factor -- are adjustments to the model that tend to overstate requirements. The Siting Council disagrees with the Company's stated position that "predicting that customers will use more on a given day is the best possible route to assure that we always have sufficient supplies." This position caused a fundamental flaw in the Company's forecasting methodology preventing an accurate determination of requirements. While assurance of adequate supplies is important, applying safety factors at any spot in a model where there may be doubt as to the exact parameter is not the proper way to do so. A more appropriate method might use sensitivity analyses of key variables or contingency analysis to assist in planning the proper level of supply reserve.

Accordingly, the Siting Council finds that the Company's methodology for specifying its regression model used to determine base year aggregate sendout demand by existing customers is not appropriate.

c. Forecast of Normal and Design Year Requirements

To determine normal year sendout requirements, the Company applied the regression model to normal year DD to determine base year requirements. However, the Siting Council found in Section II.C.2.d, supra, that the Company's normal year standard is not reliable and found in Section II.D.2.b.iii, supra, that the regression model is not appropriate. Next, Boston Gas adjusted its base year requirements for net load gain as determined by the interim model and marketing policies. But in Sections II.D.2.b.i and ii, supra, the Siting Council found that the interim model is not appropriate and that the Company's marketing policies do not reliably predict gross load additions or net load growth.

To determine design year sendout requirements, the Company applied the regression model to design year DD to determine base year requirements. However, in addition to the Siting Council's finding that the regression model is not appropriate, the Siting Council found in Section II.C.2.e, supra, that the Company's design year planning standard is neither appropriate nor reliable. Next, Boston Gas adjusted its base year requirements for net load gain as determined by the inappropriate interim model and the unreliable marketing policies. The Company also added its four percent cold snap factor to days in a design year with 40 DD or more. The Siting Council criticized the logic behind this factor, a criticism which lended support to the finding that the regression model is not appropriate.

The two other differences between the Company's normal year and design year forecasts are that the Company added all load growth prior to the onset of the heating season and assumed that no conservation, load losses, or attrition occurred during the given forecast year. The increase in annual requirements due to these two differences was not quantified during the proceeding -- two more cases of Boston Gas applying conservative assumptions without analyzing the effects on its sendout forecast.

Accordingly, the Siting Council finds that the Company's forecasts of normal year and design year sendout requirements are not reliable.

3. Conclusions

At the outset, the Siting Council finds that the three parts constituting the basic structure of the Company's new sendout forecasting methodology -- forecasting potential market demand, establishing marketing policies that maximize the benefits of that potential demand to customers and the Company, and analyzing historical sendout by existing customers -- is an appropriate sendout forecasting methodology for Boston Gas. However, the Siting Council has found that the details of each of these three parts of the methodology are not appropriately and/or reliably designed and executed.

Based on the record in this proceeding, the Siting Council finds that Boston Gas has failed to establish that its normal year and design year forecasting methodologies are appropriate and the resulting forecasts of normal year and design year requirements are reliable.[19]

19/The Siting Council makes no finding on (footnote continued) accordingly, the Siting Council finds that Boston Gas has failed to establish that it based its normal year and design year forecasts on reasonable statistical projection methods.

E. Forecast of Design Day Requirements

1. Description

Boston Gas' methodology for forecasting its design day requirements is the same as the methodology for forecasting design year requirements (see Section II.D.1, supra) except that the design day methodology only forecasts a single day. The Company's design day assumptions -- a 73 DD in January following two consecutive cold days, gross load growth for a given year, all load growth occurring prior to the design day, and Commonwealth Gas Company contractual obligations[20] -- resulted in the design day estimate for 1986-87 shown in Table 3.

Ms. Michalek testified that the Company expects its design day forecast to be accurate -- that is, neither overforecasted nor underforecasted (Tr. 1/5/87, p. 104). In its response to Condition One, however, Boston Gas studied ten cold days that occurred during 1985-86 and found that those days were overforecast in the 1985 Forecast by an average of 36.7 MDth (Exh. BGC-2, Appendix A, Response to Condition One). Ms. Michalek stated that "The sendouts did not occur as high as we expected them to occur, but the Company follows that with if it occurred once, it can occur again" (Tr. 1/14/87, p. 152). She also testified, in reference to design day planning, that "We feel that we have planned for the worse possible case" (Tr. 1/5/87, p. 124).

(footnote continued) the reviewability of the Company's new forecasting methodology in this proceeding. While the reviewability of the new forecasting methodology was not a major issue in this proceeding, it may be in future proceedings. Therefore, in its initial filing in future proceedings, Boston Gas must substantiate all aspects of the forecast methodology providing complete descriptions and arguments, and references to all data sources.

20/Boston Gas provides firm LNG supplies to Commonwealth at the rate of five MDth per day from December 23 through February 14 (Tr. 1/5/87, pp. 119-121).

The Company's forecast of design day based on the design year methodology resulted in an estimate of 711.6 MDth (Exh. EFSC-27) A forecast of design day using equivalent inputs to the normal year methodology (i.e., a 73 DD in January following two consecutive cold days, net load growth, normal addition of load growth throughout the year, and Commonwealth contractual obligations) resulted in an estimate of 674.4 MDth (Exh BGC-3[21]). The 37.2 MDth difference between these two methodologies is attributed to the four percent cold snap factor and the conservative approach to load growth additions (Exh. BGC-2, Sec. One, p. 19; Tr. 1/5/87, pp. 124-125; Tr. 1/14/87, pp. 119-120, 144-145; Tr. 5/7/87, pp. 42-45).

The Company chose January for its design day because that month is, on average, the coldest month during the year with the average coldest day occurring on January 31 (Tr. 1/14/87, pp. 137-138). The design day sendout equation as summarized in Table 2 reflected this observation by having a greater parameter for January than any other month.

2. Analysis

a. Previous Conditions

In Condition One, the Siting Council ordered the Company to compare its design day load growth forecast in 1985-86 to the actual normalized peak day experienced. In response to this condition, Boston Gas filed an analysis of its 1985-86 design day load growth (Exh. BGC-2, Appendix A, Response to Condition One). That response included an analysis comparing the actual sendouts on ten cold days during 1985-86 to the sendouts forecasted (id.). The Company prepared forecasts based on annual load additions of 2500 MMCF and 766 MMCF[22] and found that,

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21/The 73 DD sendout based on the normal year methodology, as shown in Exh. BGC-3, was adjusted for a baseload of 65 MDth and a 5 MDth contractual obligation to serve Commonwealth Gas Company on a design day consistent with Exh. EFSC-27.

22/For a discussion of the different load growth scenarios, see Section II.D.2.a, supra.

with the exception of one day, the forecast consistently overpredicted requirements in both load growth scenarios (id.). Boston Gas justified the accuracy of its forecast by stating that, "given that customers behave as forecasted only one out of ten cold days, the Company still must plan for that behavior to occur. This is fundamental to Boston Gas' peak day capacity planning" (id.).

Based on this record, the Siting Council finds that Boston Gas complied with that part of Condition One relating to the design day forecast.

b. Design Day Forecasting Methodology

The Siting Council previously found that the Company's design year forecasting methodology is not appropriate (see Sections II.D.2 and 3, supra). Since the design day forecast is based on the same methodology except for the differences outlined in Section II.E.1, supra, the Siting Council also finds that the Company's design day forecasting methodology is not appropriate.

c. Design Day Requirements

The Siting Council rejects the Company's assertion that its design day forecast predicts design day sendout requirements reliably. The record is replete with evidence that the Company's design day forecast is strongly biased toward overforecasting requirements. The Company's own witness admitted that Boston Gas has consistently overforecasted requirements which she justified by stating that the Company has planned for the worst possible case.

Boston Gas stated that a fundamental premise of the Company's design day methodology is that, "if it occurred once, it can occur again." The Siting Council has already found that this methodology is not appropriate or reliable (see Section II.C.2.f, supra). But even accepting the Company's premise, the Company applied a more strict standard in its design day sendout forecast than actually occurred: the Company based its design day on an actual occurrence of 73 DD on February 9, 1934 (Exh. BGC-2, Table DD; Exh. BGC-1), yet assumed in its forecast that 73 DD would occur in January rather than February. This seemingly minor difference added 33.9 MDth (five percent) to the sendout determination (Exh. EFSC-27).

Adjusting the Company's forecast simultaneously for the historical occurrence of 73 DD in February and for the more logical normal year forecast assumptions of net load growth, normal addition of load growth throughout the year, and no cold snap factor, the design day sendout estimate would be 641.7 MDth, about ten percent less than the Company's design day estimate of 711.6 MDth. While the lack of an appropriate or reliable design day sendout forecasting methodology lends considerable confusion as to exactly how biased toward overforecasting that methodology has become, it is clear that the amount of conservatism built into the forecast is not managed properly.

In its last decision the Siting Council noted that forecasting as reliably as possible is important from both a reliability and least-cost planning standpoint. Boston Gas Company, et al., EFSC 84-25, pp. 18-19 (1986). In addition, the Siting Council suggested that a better method of accounting for uncertainties might be in the Company's determination of supply reserve (id., pp. 18-19, 44). Boston Gas, however, continues to insist that supply reliability is so much more important than least-cost planning that the Boston Gas Staff directly responsible for the design day forecast and supply plan are not even aware of how the Company has considered the cost of overconservatism (Tr. 1/14/87, pp. 125-128). The record in this proceeding provides no evidence of any effort by the Company to identify, evaluate, or control the layers of conservatism built into its design day forecast.

Accordingly, the Siting Council finds that the Company's forecast of design day requirements is not reliable.

3. Conclusions

Based on the record in this proceeding, the Siting Council finds that Boston Gas has failed to establish that its design day forecast methodology is appropriate and that the resulting forecast of design day requirements is reliable. Accordingly, the Siting Council finds that Boston Gas has failed to establish that it based its design day forecast on reasonable statistical projection methods.

F. Summary

The Siting Council has found that Boston Gas has not adequately justified the methodologies used to establish its normal year, design year, and design day planning standards as required by Condition Nine of the Siting Council's previous decision. In addition, the Siting Council has found that Boston Gas failed to comply fully with Condition Two and to comply with that part of Condition Three required in the 1986 forecast filing.

The Siting Council has also found that the Company used inappropriate forecasting methodologies leading to unreliable forecasts of normal year, design year, and design day requirements. Thus, we found that Boston Gas failed to establish that it based its sendout forecasts on reasonable statistical projection methods. Therefore, the Siting Council finds that the Company's forecasts do not provide sound bases for resource planning decisions.

Accordingly, the Siting Council hereby REJECTS the Company'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. Berkshire Gas Company, 14 DOMSC 107, 128 (1986); Holyoke Gas and Electric Department, 15 DOMSC 1, 27 (1986); Fitchburg Gas and Electric Light Company, 15 DOMSC 39, 54 (1986); Westfield Gas and Electric Light Department, 15 DOMSC 67, 72 (1986); Fall River Gas Company, 15 DOMSC 97, 111 (1986). 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 transportation projects that are 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.[23] Berkshire Gas Company, EFSC 86-29, p. 17 (1987).

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. Id.

In adopting an expanded definition of adequacy for gas companies,

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23/ 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, EFSC 84-25, p. 33 (1986); Fitchburg Gas and Electric Light Company, 15 DOMSC 39, 53 (1986); Fall River Gas Company, 15 DOMSC 97, 115 (1986); Berkshire Gas Company, 14 DOMSC 107, 127 (1986); Bay State Gas Company, 14 DOMSC 143, 168 (1986); Essex County Gas Company, 14 DOMSC 189, 201-202 (1986).

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. Id., p. 18.

The Siting Council also reviews the cost of a utility's supply plan in terms of cost minimization, subject to trade-offs with adequacy of supplies. Id.

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 forecasts founded on accurate historical information and sound projection methods. Id.

B. Previous Supply Plan Conditions

1. Description

In its previous review of Boston Gas' supply plan, the Siting Council approved the Company's supply plan subject to five conditions. In Condition Four, Boston Gas was ordered to explain how it planned to transport and dispatch the large volumes of propane that the Company might need to receive from Dorchester Sea-3 Products, Inc. in Newington, New Hampshire. Boston Gas Company, et al., EFSC 84-25, pp. 29-30, 49 (1986). In Condition Five of its last decision, the Siting Council ordered Boston Gas to report on the operating limitations at LNG facilities that it owns or retains for storage capacity, and to report whether it has the ability to replenish its LNG inventories during a non-heating season or justify why such an ability is not necessary. Id., pp. 43, 49-50. In Condition Six, the Siting Council ordered Boston Gas to disaggregate by LNG tank location its category "LNG From Storage" in Tables G-22 and G-23 in all future filings. Id., pp. 43, 50. In Condition Seven, the Company was ordered to file an updated version of its contingency plan for meeting design year requirements in the event of a DOMAC LNG supply disruption. Id., pp. 44, 50. In Condition Eight, the Siting Council ordered the Company to file a contingency plan in the form of Table G-23 for the event that DOMAC supplies are not available on a design day. Id., pp. 44, 50.

In addition, as Condition Nine, the Siting Council ordered Boston Gas to comply with the Siting Council's Order in Evaluation of Standards and Procedures for Reviewing Sendout Forecasts and Supply Plans of Natural Gas Utilities, 14 DOMSC 95 (1986), and that Order's implementation in Administrative Bulletin 86-1. Boston Gas Company, et al., EFSC 84-25, pp. 46-48, 50 (1986). Finally, as Condition Ten, the Siting Council ordered Boston Gas to report on the status of DOMAC negotiations, including any volumes requested and the timing of those volumes, by July 15, 1986. Id., p. 50.

2. Compliance

In Condition Six of its last decision, the Siting Council ordered the Company to disaggregate its LNG supplies in forecast Tables G-22 and G-23. Since the Company's 1986 forecast filing included such disaggregated tables (Exh. BGC-2, Tables G-22D-LNG, G-22N-LNG, and G-23), the Siting Council finds that Boston Gas has complied with Condition Six.[24]

In Condition Seven, the Siting Council ordered Boston Gas to file contingency plans for the event of a DOMAC LNG supply disruption. In

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24/In Condition Six, the Siting Council ordered Boston Gas to disaggregate its LNG supplies in all future filings. Therefore, our finding assumes the Company will continue to file its LNG supply plan in a similarly disaggregated form.

its response to Condition Seven, Boston Gas asserted that no deliveries of DOMAC LNG were included in the forecast, and referred the Siting Council to Tables G-22N and G-22D (Exh. BGC-2, Appendix A, Response to Conditon Seven). The Siting Council finds that Tables G-22N and G-22D support this assertion. Accordingly, we find that Boston Gas has complied with Condition Seven.

In response to Condition Ten in which the Siting Council required Boston Gas to file a status report on DOMAC negotiations, the Company filed a letter on July 14, 1986 (dated July 11, 1986) updating the status of such negotiations. Attached to that letter were two more letters between officials of Boston Gas and DOMAC indicating the nature of certain issues of concern to the parties.[25] Accordingly, the Siting Council finds that the Company has complied with Condition Ten.

Compliance with Conditions Four, Five, Eight, and Nine is discussed in Sections III.C and III.D, *infra*.

C. Resources

1. Pipeline Gas and Storage Services

a. Existing Deliveries and Services

Boston Gas receives deliveries of pipeline supplies and storage return gas from Algonquin Gas Transmission Company and Tennessee Gas Pipeline Company (Exh. BGC-2, Sec. One, pp. 22-27). Algonquin delivers firm gas and provides storage services under rate schedules F-1, F-2, F-3, WS-1, ST-B, and SS-III;[26] Tennessee delivers firm gas under rate schedule CD-6 (*id.*). In addition, Boston Gas has agreements with

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25/A copy of the letter filed July 14, 1986 with attachments was included in Exh. BGC-2, Appendix A, Response to Condition Ten.

26/At the time of the forecast filing, Algonquin's F-2 and F-3 contracts, sometimes jointly known as the "CONTEAL" supplies, were planned supplies set for delivery beginning on November 1, 1986 (Exh. BGC-2, Table G-24). Ms. Michalek verified that Algonquin was indeed providing CONTEAL service to Boston Gas during the 1986-87 heating season (Tr. 1/5/87, p. 33).

Honeoye Storage Corporation ("Honeoye"), Consolidated Gas Supply Corporation ("Consolidated"), and Penn-York Energy Corporation ("Penn-York") for underground storage services in New York and Pennsylvania (id., p. 31). Storage volumes under these three agreements are returned by Tennessee under rate schedule FSST-NE (id., p. 32). The Company's maximum daily quantity ("MDQ") and annual contract quantity ("ACQ") under each of these contracts are summarized in Table 4.

The only pipeline gas contract set to expire during the five-year forecast period is Algonquin's WS-1 contract (id., Table G-24). Boston Gas stated, however, that it "is of the opinion that deliveries under Algonquin's WS-1 rate schedule will continue at current annual and daily levels throughout the period covered by this forecast" (id., Sec. One, p. 24). Therefore, the Siting Council finds that it is reasonable for Boston Gas to assume for base case planning that supplies will be available under Algonquin's WS-1 contract for the duration of the forecast period.

In addition, the Company reported that the Federal Energy Regulatory Commission ("FERC") issued its final approval of Algonquin's request to abandon its substitute natural gas ("SNG") service provided under rate schedule SNG-1 (id.).

b. Planned Deliveries and Services

i. Boundary/INGS

Boston Gas plans to begin receiving supplies either from Boundary Gas, Inc. ("Boundary") under Phase II of Boundary's Canadian import project or from Tennessee through its Interim Natural Gas Service ("INGS") (Exh. BGC-2, Sec. One, pp. 30-31, Tables G-22 and G-23; Exh. EFSC-88). Tennessee received FERC approval to provide INGS service which is proposed to be succeeded by Boundary volumes if FERC approves a proposed settlement agreement authorizing Boundary Phase II volumes[27]

[27]/Due to the highly integrated nature of the Boundary and INGS projects, the Siting Council will refer to them as Boundary/INGS.

(Exh. EFSC-88). Subsequent to FERC's approval of INGS, Boston Gas re-estimated the date for receiving Boundary/INGS volumes as November 1, 1987 (Exh. BGC-2, Sec. One, p. 31; Exh. EFSC-88). The Boundary/INGS proposal provides for an ACQ of 3,913.5 MDth and an MDQ of 10.7 MDth (Exh. BGC-2, Sec. One, p. 31).

ii. Alberta Northeast

Boston Gas indicated that it had signed a precedent agreement with Alberta Northeast Gas, Limited ("Alberta Northeast" or "ANE") for the purchase of Canadian gas beginning November 1, 1990 at an MDQ of 17.5 MDth and an ACQ of 6,387.5 MDth (Exh. BGC-2, Sec. One, p. 31). Boston Gas also indicated that, at this stage, its only obligation is to apply for the necessary regulatory authority for transportation, and that, once such approval is granted, Boston Gas could withdraw from the project "at its' sole discretion" (Exh. EFSC-51). In addition, the Company provided that if Boston Gas and Alberta Northeast have not received the necessary authorization by August 1, 1987, then either party may terminate the precedent agreement (id.). Ms. Michalek termed the Company's commitment to Alberta Northeast as "tentative" (Tr. 5/6/87, p. 27; see also Exh. EFSC-51).[28]

iii. NOREX

Ms. Michalek testified that Boston Gas chose to expand its Tennessee contract demand through the "NOREX" project, a project succeeding the Tennessee CD-6 AVL Expansion project discussed in the Company's original filing (Tr. 5/6/87, pp. 12, 21; Exh. EFSC-110; Exh. BGC-2, Sec. One, p. 27). Boston Gas provided a precedent agreement between the Company and Tennessee dated May 5, 1987 outlining the NOREX arrangements (Exh. EFSC-110). The NOREX volumes would increase the

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28/Due to the tentative nature of the Alberta Northeast project, we consider delay or unavailability of this project as a contingency in our analysis of supply adequacy in Section III.D.2, infra.

Company's current CD-6 volumes by about 43.6 MDth/day[29] and about 10,000 MDth/year (Exh. EFSC-110; Exh. BGC-2, Table G-24; Tr. 5/6/87, p. 17).

The precedent agreement does not specify when such volumes would become available, although it provides that, if Tennessee has not obtained the necessary regulatory approvals by July 1, 1988, either party may terminate the agreement (Exh. EFSC-110). Ms. Michalek stated that Boston Gas expects to begin receiving the NOREX volumes in 1989, possibly in two increments (Tr. 5/6/87, pp. 17, 35; Tr. 5/15/87, pp. 35-36). She also provided that the Company has made a commitment for NOREX (5/6/87, p. 27).

2. Liquefied Natural Gas

Boston Gas has traditionally used LNG for supply and storage.

a. LNG Supplies

Boston Gas has contracts with DOMAC for LNG supply service under DOMAC's Rate Schedules GS-1 and TS-1 (Exh. BGC-2, Sec. One, p. 27). However, DOMAC's importer affiliate, Distrigas Corporation, filed for bankruptcy and stopped its deliveries of LNG (id., pp. 28-29). Based on these circumstances, Boston Gas stated that it "is not optimistic about DOMAC's ability to resume service and, as a result, no deliveries of DOMAC LNG are contemplated in this forecast" (id., p. 29).

Since the Company held approximately 700 MDth of LNG in DOMAC's Everett LNG facility prior to the 1986-87 heating season, that supply was included in the Company's supply plan for the 1986-87 heating season (id.). The Company indicated that, due to boiloff between the Company's

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29/Ms. Michalek testified that the NOREX volumes would be provided at an MDQ of about 40 MDth/day (Tr. 5/6/87, p. 17). The NOREX precedent agreement, however, indicated that the Company's total CD-6 MDQ would increase to 140.0 MDth/day from the Company's current CD-6 MDQ of 96.4 MDth/day (Exh. EFSC-110; Exh. BGC-2, Table G-24). The Siting Council assumes that the NOREX MDQ is the difference between the precedent agreement MDQ and current MDQ, 43.6 MDth/day.

September 2, 1986 filing date and the start of the heating season, about 603 MDth of DOMAC LNG would be available for the 1986-87 heating season (id., Table G-22; Exh. EFSC-20). However, the Company added that it expected to use all such volumes during the 1986-87 heating season, and therefore DOMAC LNG was removed from the Company's supply plan beginning with the 1986-87 non-heating season on April 1, 1987 (Exh. BGC-2, Sec. One, p. 29).

Thus, the Siting Council finds that Boston Gas made a reasonable assumption in its base case planning for the 1986-87 heating season that it would have 603 MDth of DOMAC LNG.

b. LNG Vaporization Capability

i. Existing Vaporization Capability

The Company[30] operates LNG storage facilities at Commercial Point (Dorchester), Lynn, and Salem (Exh. BGC-2, Sec. One, p. 32). In addition, the Company retains rights to storage and vaporization at DOMAC's LNG facility in Everett and rights to storage, but not vaporization, at Algonquin's LNG facility in Providence, RI (id., pp. 27-28, 33). Table 5 summarizes the Company's LNG arrangements.

In describing its LNG vaporization capability, Boston Gas differentiated between "vaporization capacity" and "standby capacity" (id., p. 32) offerring the following explanation:

> To insure peak day coverage and to provide for the contingency of equipment malfunction, Boston Gas and Mass. LNG provide for standby capacity at their major peakshaving facilities by designating one LNG vaporization unit or other production facility in reserve on standby. Such assignment of standby capacity far exceeds the normal practice of designating as "standby" the equivalency of the largest single unit. (id.)

30/Since Mass. LNG is a wholly owned subsidiary of Boston Gas and Mass. LNG's operations are closely related to those of Boston Gas (Exh. BGC-2, Intro., p. 2), the Siting Council's discussion of LNG operations will refer to Boston Gas but apply to Mass. LNG where appropriate.

The Company stated its general opinion that "maintaining standby vaporization capacity at each of the Company's LNG facilities increases the overall reliability of its supply system" in three ways: (1) backing up other vaporizers in case of equipment malfunction; (2) boosting operating pressures within a given area of the distribution system;[31] and (3) meeting extreme or design day sendouts (Exhs. EFSC-6 and EFSC-38; Tr. 1/5/87, p. 104). Essentially, Boston Gas has a policy of maintaining a standby vaporization or other production unit at each major peakshaving facility to ensure a minimum production capability at each location for operating purposes.

The Siting Council has previously noted the Company's operating procedure of providing for one standby vaporizer at each LNG facility to ensure system integrity and to provide for the contingency of equipment malfunction. Boston Gas Company, et al., 4 DOMSC 50, 75 (1980). For the purposes of our review, we find that this procedure is a reasonable operating practice and therefore serves as a basic assumption to be considered in supply planning.

In this proceeding, the Company has asserted that, from a supply planning standpoint, designating the equivalency of the largest vaporization or other production unit on its system as standby capacity adequately ensures a minimum system-wide production capability and therefore all capacity considered standby for operating purposes, except the equivalence of the largest unit, is available for the base case supply plan (Exh. BGC-2, Sec. One, p. 32; Exhs. EFSC-6 and EFSC-8).

Since standby production capacity is available from a supply standpoint, and since replacing available standby capacity with other supplemental supplies would have unneccessary cost implications, we find that the Company's policy of designating as standby the equivalency of the largest vaporization or other production unit is reasonable for base case supply planning purposes. Therefore, the Siting Council finds that

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31/The Company never clarified exactly how it would "boost operating pressures within a given area" (Exh. EFSC-6). In approving this policy, the Siting Council assumes that Boston Gas would not need to exceed the maximum allowable operating pressure of its distribution system. For further discussion of the Company's distribution system operating practices, see Section III.F, infra.

the equivalency of the largest vaporization or other production unit shall be removed from the Company's base case supply plan and that all other such units shall be included in the base case supply plan.

We accept this policy in concert with our finding that one vaporizer or other production unit at each major peakshaving facility is held as standby capacity. To ensure these policies do not conflict, the Siting Council accepts a policy of holding one vaporization or other production unit as standby at each major peakshaving facility, and includes all such units, except the equivalency of the largest, in the "production reserve" portion of the base case supply plan (see Table 7).

In regards to the Company's firm and best efforts DOMAC vaporization rights which total 111.6 MMCF per day ("MMCFD"),[32] the Company stated its position that it can call upon those rights during the 1986-87 heating season, but that it will not depend on such rights to meet peak day sendouts (Exhs. EFSC-12, EFSC-14, and BGC-2, Table G-23). Thus, Boston Gas designated those rights as standby capacity and indicated their availability as backup to the supply plan (Exhs. EFSC-7 and EFSC-70; Tr. 1/5/87, p. 105).

With respect to the Company's 45.0 MMCFD of DOMAC best efforts vaporization rights, the Company has not produced an argument justifying the classification of those rights, or any other non-firm capacity, as available on any basis for design planning. With respect to the Company's 66.6 MMCFD of firm vaporization rights, however, Boston Gas indicated that such rights were available under contract (Exh. BGC-2, Sec. One, pp. 27-28) and that supplies were available in DOMAC's Everett LNG facility for the 1986-87 heating season. Therefore, the Siting Council finds that the Company has provided sufficient justification for assuming the availability, on a standby basis, of its DOMAC vaporization rights of 66.6 MMCFD for the 1986-87 heating season.

Accordingly, the Siting Council finds that it is reasonable for Boston Gas to assume for base case planning purposes that the

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32/For consistency with normal engineering practice, the Siting Council discusses physical capacities in volumetric rather than thermal terms. In this context we assume, as Boston Gas does, that 1 MMCF is equivalent to 1 MDth (Exh. BGC-2, Sec. One, p. 23).

equivalency of the largest vaporization or other production unit is 66.6 MMCFD for the 1986-87 heating season and 62.5 MMCFD in each forecast year thereafter (see Table 5), and that such capacity should be removed from the Company's base case supply plan (see Table 7).

ii. Planned Vaporization Capacity

The Company plans to add new vaporization capacity during the forecast period.

At Commercial Point, Boston Gas plans to install an additional 62.5 MMCFD vaporizer to be in service by December 1, 1987[33] (Exh. EFSC-10). Although Boston Gas did not provide its own planning schedule for licensing, design, construction, testing, and start-up of this vaporizer, the Company had already completed licensing[34] (Exhs. EFSC-72 and EFSC-104; Tr. 1/14/87, pp. 15-17) and, in early 1987, selected a contractor to design the facility and manage construction (Exh. EFSC-10). The contractor prepared a schedule indicating testing and start-up could occur prior to the 1987-88 heating season (id.).[35]

33/In its initial filing the Company indicated that this new vaporizer would be in service by November 1, 1987 (Exh. BGC-2, Table G-16). The Company revised the in-service date to December 1, 1987 (Exh. EFSC-10).

34/The Siting Council conditionally approved the new Commercial Point vaporizer in 1980. See Boston Gas Company, et al., 4 DOMSC 50, 51 (1980). In that same decision, the Siting Council issued its conditional approval for construction of an additional vaporizer at the Company's Salem LNG facility. Id. As a condition in another Siting Council decision approving additional propane-air capacity at the Company's existing Danversport propane plant, the Siting Council ordered Boston Gas either to propose rescission of the additional Salem vaporizer or to state why such a proposal should not be made. Boston Gas Company, et al., 8 DOMSC 1, 28 (1982). The Company chose to propose rescinding the additional Salem vaporizer, and the Siting Council approved that proposal. Boston Gas Company, et al., 9 DOMSC 1, 104 (1982).

35/The City argues that Boston Gas should have a reasonable contingency plan in effect should the vaporization facility be delayed (City Brief, p. 15). In its review of Boston Gas supply adequacy, the Siting Council examines this contingency.

The Company's 1986 filing also indicated plans for addition of a new 40 MMCFD vaporizer to be installed at the Company's Lynn LNG facility (Exh. BGC-2, Table G-23 and Sec. Three, p. 1). Later, however, the Company backtracked on its selection of Lynn stating that Boston Gas was still "analyzing possible sites" for the additional capacity (Exh. EFSC-11). While the Company stated its intention of placing an additional 40 MMCFD of vaporization capacity in service by November 1, 1988 (id.; Exh. BGC-2, Sec. Three, p. 1), Boston Gas could not provide any indication of how it planned to do so (Exhs. EFSC-11 and EFSC-38; Tr. 5/6/87, p. 81). Ms. Michalek testified on behalf of Boston Gas on its ability to place such a vaporizer in service:

> I don't think we have anything documented that has a critical path schedule for installing a vaporizer, but I think mid-level management, as well as senior management, knows approximately how long the whole process takes in selecting, in designing, and deciding where its going to go. So it's not anything that we have as part of a company policy that this is how long it takes to put in a vaporizer, but I think that the people who are in charge of making these decisions understand how long it will take.
>
> Q Do you have any documentation to support that?
>
> A No, I don't. (Tr. 5/6/87, pp. 81-82)

Not only has Boston Gas been unable to provide a reasonable basis for determining whether it could place a new vaporizer in service at Lynn by November 1, 1988, the Company has actually lost progress by deciding to reopen the site-selection process.

Therefore, the Siting Council finds that Boston Gas has failed to establish that it could place a new 40 MMCFD vaporization unit in service by November 1, 1988.[36]

36/We consider this finding in our analysis of supply plan contingencies in Section III.D.2, infra.

c. LNG Storage and Refill

i. Description

In part of Condition Five in its last decision, the Siting Council ordered Boston Gas to report on the operating limitations of its LNG facilities including tank capacity, form of LNG replenishment, rate at which LNG can be replenished in both the heating and the non-heating seasons, and the factors limiting the rate of replenishment.

In its response to this condition, the Company reported the capacities and capabilities of each of its LNG facilities and those it retains for storage (see Table 5) (Exh. BGC-2, Appendix A, Response to Condition Five). The total storage volume (not including DOMAC capacity) is 4540 MMCF (id.). Ms. Michalek stated that, on a thermal basis, the capacity could be as high as 4900 MDth, but that for planning purposes Boston Gas uses 4540 MMCF "since that is the most conservative way of looking at it" (Tr. 5/6/87, pp. 57-63). The Siting Council finds that a reasonable planning assumption for Boston Gas is that 4540 MMCF (4540 MDth) represents full LNG storage inventories.[37]

Boston Gas also reported that it plans to refill its LNG storage throughout the forecast period by liquefying pipeline gas at the Commercial Point and Lynn LNG facilities whose respective liquefaction capabilities are claimed to be 6.0 MMCFD and 7.35 MMCFD[38] (Exh. BGC-2, Appendix A, Response to Condition Five, Sec. One, p. 33, and Tables G-22D-LNG and G-22N-LNG). To refill LNG volumes at Salem and Algonquin LNG, the Company must truck LNG produced at Commercial Point and Lynn or

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37/This finding excludes DOMAC storage in Everett.

38/While Boston Gas reported that its "Liquefaction Capacity" is 6.0 MMCFD at Commercial Point and 7.35 MMCFD at Lynn, Ms. Michalek testified that "the stated capacity is merely a bench mark that we use for modeling as kind of an average day of liquefaction. Some days it's going to be significantly above that; some days significantly below that" (Tr. 5/6/87, pp. 68-69). Thus, to avoid confusion, the Siting Council refers to the maximum average liquefaction rate that Boston Gas can consistently achieve over an extended period of time as "liquefaction capability."

from DOMAC's Everett LNG facility (id., Appendix A, Response to Condition Five). Boston Gas indicated that the factor limiting its ability to refill LNG is the availability of pipeline gas (id.).

Based on this response, the Siting Council finds that Boston Gas has complied with that part of Condition Five requiring it to report on its LNG storage capacity and refill ability.

ii. Arguments and Analysis

As part of Condition Five, the Siting Council ordered Boston Gas to demonstrate its ability to refill its entire LNG storage capacity at each LNG facility during any given non-heating season. If Boston Gas were unable to demonstrate such an ability, then the Company was ordered to either state how it planned to acquire such an ability or justify why such an ability is not necessary.

The Company plans to refill its LNG storage throughout the forecast period by liquefaction. But since the Company's total LNG tank capacity is 4540 MMCF and total claimed liquefaction capability is 13.35 MMCFD, the Company would require 340 days to refill its LNG requirements -- a time requirement exceeding the 214 days in a non-heating season. Accordingly, the Siting Council finds that Boston Gas failed to comply with the part of Condition Five requiring the Company to document its ability to refill its entire LNG storage through its stated plan (i.e., liquefaction).

To determine whether the Company is nevertheless prepared to meet its forecasted LNG storage refill requirements, the Siting Council examines the Company's ability to refill its LNG requirements under design year assumptions for 1986-87.

As a basic planning assumption, a company must establish that, by a certain date, it has full LNG inventories such that it is in position to meet LNG requirements should a design year occur. The record demonstrates that Boston Gas plans to have full LNG inventories by November 1 (Exh. EFSC-40; Tr. 5/6/87, p. 77) despite Ms. Michalek's disclaimer that "it may not be exactly November 1st, but it would be prior to vaporization requirements" (Tr. 5/6/87, p. 64). Therefore, the Siting Council finds that a basic planning assumption for Boston Gas is that it will have full LNG inventories by November 1 of each year.

Boston Gas stated that, in addition to 206 days during the non-heating season, there are 34 days during a 1986-87 design heating season in which excess pipeline capacity would allow the Company to liquefy[39] (Exh. BGC-2, Appendix A, Response to Condition Five). Other evidence in the record, however, indicated that Boston Gas would not be able to liquefy on 34 days during a 1986-87 heating season. The Company provided a daily analysis of its 1986-87 design year supply plan which indicated that there would be excess pipeline capacity on 36 days during the heating season (Exh. EFSC-22). However, the Company's analysis indicated that 26 of those 36 days occur between November 1 and the projected first day of vaporization on December 16 (id.). Thus, those 26 days of excess pipeline supplies prior to December 16 are of little use for refilling LNG storage since they could only be used to replace LNG boiloff, estimated to occur at 2.6 MMCFD (id.). On one of the remaining ten days in which excess pipeline capacity would allow liquefaction during the heating season, there would be insufficient excess capacity to liquefy at the Company's claimed capacities (id.). Therefore, the Siting Council finds that the Company's 1986-87 design year supply 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.

The Company stated that its fully rated liquefaction capabilities are 6.0 MMCFD at Commercial Point and 7.35 MMCFD at Lynn (Exh. BGC-2, Appendix A, Response to Condition Five). To document the Company's ability to refill at these rates, Boston Gas provided daily liquefaction data for both LNG facilities for the period April 1986 through April 1987 (Exhs. EFSC-40 and EFSC-113). Prior to April 1986, Boston Gas had not liquefied large quantities of gas since about the mid-1970s (Tr. 5/6/87, p. 64). Table 6 summarizes key aspects of the Company's recent liquefaction experience.

39/The Company added that it could use supplemental winter supplies such as ST-B, SS-III, and FSST-NE to increase the number of days of liquefaction, but provided no analysis indicating how it would do so (Exh. BGC-2, Appendix A, Response to Condition Five).

The City argues that, while Boston Gas has claimed that its facilities at Commercial Point and Lynn are capable of liquefying at 6.0 MMCFD and 7.35 MMCFD, the historical data do not support such a claim (City Brief, p. 13). The City bases its argument on (1) the recurrent mechanical failures since April 1986 and (2) the Company's inability to maintain its rated capabilities consistently (id., pp. 13-14). In reply, Boston Gas maintains that the City failed to establish that the Company needed to liquefy at average rates higher than the actual 1986-87 rates (Company Reply Brief, p. 9). The Company also maintains that the record reflects that, even with the associated operational problems, it can expect to liquefy at the rated capabilities should those amounts be deemed necessary (id.).

The record indicates that the liquefaction problems[40] consistently experienced by the Company have prevented it from liquefying for extended periods of time (Exhs. EFSC-40 and EFSC-113; Tr. 5/6/87, pp. 65-68). For instance, at Commercial Point, Boston Gas experienced 18 separate problems that caused liquefaction shutdown for one day or more resulting in a total of 68 days in which the Company could not liquefy (id.). At Lynn, the Company experienced 13 separate problems preventing liquefaction on 64 days (id.).

Ms. Michalek testified that Boston Gas expects future liquefaction availability to improve over that of 1986 because of the experience gained during 1986 (Tr. 5/6/87, pp. 65-68). Since 1986 was the first year of substantial liquefaction since the mid-1970s, Boston Gas believes it experienced many problems that should not be as extensive in future years (id.). Yet at the same time an internal Company memorandum acknowledged that problems shutting down liquefaction can and do occur:

> Both liquefaction facilities, although maintained properly, have shown in the past two years that sustained operating requirements (use of more than 100 day/year) involve some down-time and extraordinary maintenance and repairs. (Exh. EFSC-110, p. 3)

40/Boston Gas divided problems preventing liquefaction into four categories: (1) mechanical problems; (2) high dew point of the gas; (3) deryming and defrosting of liquefaction equipment; and (4) vaporization mode and insufficient supply (Exh. EFSC-40; Tr. 5/6/87, pp. 65-68).

The City asserts that the Company's liquefaction performance was below forecast assumptions because the Company only liquefied at average rates of 3.7 MMCFD and 3.67 MMCFD at Commercial Point and Lynn, respectively (City Brief, p. 13). While the Siting Council finds that average rates of 3.91 MMCFD and 3.94 MMCFD, respectively, better reflect the evidence in the record (see Table 6), in either case, the Company's liquefaction performance has indeed failed to meet forecast assumptions. The information in row 9 of Table 6 suggests that, even ignoring all problems that have shut down liquefaction in the past, Boston Gas failed to consistently achieve its claimed capabilities, instead only achieving average rates of 5.20 MMCFD and 6.25 MMCFD at Commercial Point and Lynn, respectively.

Ms. Michalek testified that, given that 1986 was the first year of heavy liquefaction, determining average liquefaction rates based on 1986 data would be taking such data out of context and would not be "giving our liquefaction the consideration it deserves" (Tr. 5/6/87, pp. 69-70). She asserted that, "although it's an indication of what we did last year, it's by no means an indication of what can be done" (id., p. 70).

The Siting Council agrees with the City that Boston Gas has not established that it can liquefy at its claimed capabilities. While Ms. Michalek asserted that 1986 is not an accurate reflection of the Company's liquefaction capability, it is the only year for which recent historical data available, and it conflicts with the Company's claim that it can consistently liquefy at 6.0 MMCFD at Commercial Point and 7.35 MMCFD at Lynn. As the Company noted, it had not liquefied for about ten years and therefore it needed to regain liquefaction operating experience. While it may very well be possible for the Company to achieve its claimed liquefaction capabilities for long periods, Boston Gas failed to establish in this proceeding that it could do so. Therefore, the Siting Council rejects the Company's assertion that it can expect to liquefy at the claimed capabilities of 6.0 MMCFD at Commercial Point and 7.35 MMCFD at Lynn should those amounts be deemed necessary.

But even taking into account the uncertainty surrounding probable liquefaction capabilities, the Company's inability to refill its 1986-87 design liquefaction requirements under reasonable alternate liquefaction capacity assumptions is clear. Thus far, there are three estimated average liquefaction rates for Commercial Point and Lynn: (1) 3.91 MMCFD and 3.94 MMCFD, respectively, based on the actual data provided for the Company ("case one"); (2) 5.20 MMCFD and 6.25 MMCFD, respectively, assuming historical liquefaction rates but no problems preventing liquefaction ("case two"); and (3) 6.0 MMCFD and 7.35 MMCFD, respectively, the Company's claimed capabilities ("case three"). To refill its 1986-87 design year LNG requirements (see Table 6), at the rates in case one, the Company would require 378 days at Commercial Point and 400 days at Lynn; at the rates in case two, the Company would require 284 days at Commercial Point and 252 days at Lynn; at the rates in case three, the Company would require 246 days at Commercial Point and 214 days at Lynn. These time periods compare with the 215 days actually available for liquefaction established earlier in this section.

Using the assumptions most favorable to the Company -- case three with the Company's claimed capabilities and no liquefaction interruptions -- the Company would require 246 days to refill 1986-87 design requirements at Commercial Point -- a clear inadequacy given only 215 days of possible liquefaction in a design year. At Lynn's claimed capability, the Company would require 214 days to refill requirements -- a theoretical, but unlikely, possibility, particularly given the Company's acknowledgement that both the Commercial Point and Lynn liquefaction facilities have demonstrated that "sustained operating requirements (use of more than 100 day/year) involve some down-time and extraordinary maintenance and repairs." As noted above, the other two cases provide substantially worse results.

Accordingly, the Siting Council finds that Boston Gas has not demonstrated its ability to refill its LNG storage facilities in all design years during the forecast period. The Siting Council orders Boston Gas in its next forecast filing (1) to provide a re-evaluation of its Commercial Point and Lynn liquefaction capabilities that adequately considers historical liquefaction experience, (2) to demonstrate that its re-evaluated liquefaction capabilities are sufficient to meet forecasted liquefaction requirements in all forecast years, and (3) if the Company cannot demonstrate such liquefaction capability, to propose a plan for securing adequate LNG refill capability and a schedule for implementing such a plan.

3. Propane

a. Propane Supplies

Boston Gas has an agreement with Dorchester Sea-3 Products, Inc. ("Sea-3") to terminal up to 50 million gallons of propane at Sea-3's Newington, NH propane terminal (Exh. BGC-2, Sec. One, p. 29). Sea-3 also supplies Boston Gas with propane and arranges all shipments (Exhs. EFSC-43 and EFSC-80). Boston Gas stated that its terminalling arrangement provides supply flexibility and helps provide cost-effective service since it avoids firm take-or-pay obligations for large quantities of propane (Exh. BGC-2, Sec. One, p. 30).

The Company's 1986 forecast indicated that the most propane required during the forecast period would be approximately 3,315 MDth (36 million gallons) during a 1987-88 design heating season (Exh. BGC-2, Table G-22D).

b. Propane Transportation Capability

i. Description

Transgas, Inc. ("Transgas") trucks all of the Company's contracted propane from Sea-3's terminal in Newington, NH to the Company's various propane dispatch facilities (Exh. EFSC-80). The Company's contract with Transgas ("Transgas contract") specifies that Transgas must have available for Boston Gas 15 propane tractor-trailer units ("propane trucks") on a 24-hour per day, seven-day per week basis for the 1986-87 heating season (Exh. BGC-2, Appendix A, Response to Condition Four). In addition, Transgas would make available any extra propane trucks on a best efforts-basis (id.).

The Company originally estimated that these trucks could make a total of 60 round trips per day delivering a total of 607,500 gallons (55.7 MDth) (id.). However, after the Company signed a contract with

Transgas in January 1987, Ms. Michalek stated that Transgas is "guaranteeing us 15 trucks and 50 deliveries a day"[41] (Tr. 1/5/87, pp. 17-18, 101-102, and 172; Tr. 1/14/87, p. 27). Under the assumption that each propane truck has a capacity of 9,500 gallons, the firm delivery rate of the Trangas contract is 475,000 gallons (43.6 MDth) per day (Exh. EFSC-44; Tr. 1/5/87, p. 100). Based on this daily trucking rate, the Company estimated that between 75 and 120 days would be required to move the 36 million gallons (3,315 MDth) of propane required under 1987-88 design year assumptions (Exh. EFSC-44).

ii. Arguments

The City argues that it is necessary to step away from the mechanical mathematics of gallons per trucks and deliveries per day and focus attention on the common sense reality of what the Company plans to do (City Brief, p. 7). First, the City maintains that propane deliveries must be made under the worst possible weather and road conditions which may keep the trucks from making one round trip per day let alone four (id., pp. 7-8). In addition, the City asserts that propane trucks and drivers may not be able to maintain a sufficient trucking rate over a long period of time since the harsh weather conditions and the relentless demands of four trips per day will take a toll on both the drivers and the trucks (id., p. 8). Finally, the City maintains that the Company has little room for error in trucking propane to its dispatch facilities due to the lack of on-site propane storage facilities (id.; City Reply Brief, pp. 3-4).

The Company maintains that the most propane anticipated in any design year is 36 million gallons in 1987-88, and further maintains that the record shows that during periods of high demand Boston Gas has trucked at up to 60 deliveries per day (Company Reply Brief, p. 6).

41/Based on our review of the Transgas contract, it does not indicate an upper limit of 50 propane deliveries per day, but rather a limit on the number of propane trucks available for the Company's use (Exh. EFSC-25). However, since Ms. Michalek stated the Company's position that Transgas will only provide 50 firm deliveries per day, the Siting Council accepts the Company's assumption.

However, the Company also maintains that rather than relying on trucking propane for a certain number of consecutive days in the winter, the Company's supply plan calls for baseloading propane on marginally cold days in order to conserve LNG (id.).

In addition, the Company acknowledges the limitations of its storage facilities and plans accordingly (id.). The Company asserts, however, that it is stated Company policy to have full propane inventory throughout the heating season (id., p. 7). Finally, the Company argues that it should not be required to meet every hypothetical supply scenario that can be posited as long as it establishes, as it believes it has herein, that it has adopted supply planning processes, such as maintaining full propane inventory throughout the heating season, that meet peak day and peak winter requirements (id.).

iii. Analysis

Condition Four ordered Boston Gas to report on the details of transporting propane over a long period of time and to estimate the amount of time necessary to transport 47.5 million gallons of propane. While Boston Gas provided its estimate of the rate at which Transgas could transport over an extended period of time -- 50 deliveries or 475,000 gallons per day -- once that trucking rate had been determined the Company failed to estimate the time necessary to transport 47.5 million gallons. Accordingly, the Siting Council finds that the Company failed to comply with Condition Four.

Since the most propane anticipated in any forecast year is 36 million gallons (Exh. BGC-2, Table G-22), for purposes of this forecast review the Siting Council examines the Company's ability to truck this amount during the 1987-88 heating season.

Boston Gas has 15 firm trucks[42] available to provide 50 propane deliveries per day. Based on the Company's claim that Transgas can truck at least 475,000 gallons per day, Boston Gas would need 76 days to

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42/The Siting Council cannot accept design plans based on best-efforts or non-firm commitments.

move 36 million gallons of propane. The Company, however, suggested that to dispatch design year quantities of propane it would baseload its Everett plant at about 35 MMCFD,[43] about 381,500 gallons (40 deliveries) per day. At this rate, the Company would require about 95 days to receive and dispatch design year propane quantities. Therefore, the Siting Council rejects the Company's claim that it could receive delivery of propane in less than 95 days. Based on varied degree-day patterns, the Company estimated that it could take up to 120 days, or an average of about 32 deliveries per day, to receive delivery of 36 million gallons (Exh. EFSC-43; Tr. 5/6/87, p. 42).

Ms. Michalek estimated that the longest period experienced by Boston Gas of trucking significant propane volumes was about seven days (Tr. 5/6/87, p. 44). She stated that, "Although we haven't seen extended periods of huge amounts of trucking, we feel that what we have seen is enough to make them [Transgas] a reliable carrier" (id., pp. 43-44). The only evidence the Company presented indicating Transgas' ability to deliver the services in its contract was a five-day period of trucking during January 1987. During that period Transgas averaged 44 deliveries per day (Exh. EFSC-112). A five-day period, however, does not demonstrate the trucking capability necessary to maintain an average of 32 to 40 deliveries per day for the 95 to 120 days required to truck 36 million gallons.

Accordingly, the Siting Council finds that Boston Gas has not established that it is reasonable to expect to receive delivery in a 95- to 120-day period of the 36 million gallons of propane required to meet the Company's forecasted 1987-88 design year requirements.

We agree with the City that maintaining a consistent and adequate trucking rate is of critical importance to the Company's ability to plan for and operate a reliable supply plan given the limitations of the Company's propane storage facilities. Even though Transgas' business is trucking propane during the cold winter months, and therefore Transgas

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43/Propane dispatch at 35 MMCFD represents the average of the only plan set forth by the Company for dispatching large quantities of propane (Exh. BGC-2, Appendix A, Response to Condition Four). See Section III.C.3.iii, infra.

should be prepared to provide service under a variety of weather conditions, it seems reasonable to assume that severe weather conditions could inhibit or prohibit trucking for short periods of time. Assuming Boston Gas is dispatching its propane from Everett at 35 MMCFD, the Company's Everett storage capacity of 65.6 MMCF (Exh. BGC-2, Table G-14) would allow less than two days of continued dispatch if propane deliveries were interrupted. Even if Transgas could resume trucking within two days, the Everett propane storage could have been exhausted or nearly exhausted leaving the Company in a position where any further trucking problems could not be absorbed by storage.[44]

While Boston Gas acknowledges the limitations of its storage facilities and claims that it plans accordingly, in practice the Company needs an adequate trucking capability to provide propane at a steady rate for a long period of time in order to meet its customers' requirements during a design year. While the Company argued that it does not need to truck for a certain number of consecutive days because it is baseloading propane, and while the Company's storage capacity could absorb a missed day of trucking on occasion, Boston Gas would be short of propane very quickly during a design year if trucking halted for any significant length of time.

Although we have reservations about the Company's propane storage capability, we make no findings here.[45]

c. Propane Dispatch Capability

i. Description

Boston Gas operates a major propane production facility in

44/Under these trucking and dispatching conditions, the rate at which Boston Gas could refill its propane storage would be the amount of propane trucked to Everett less the amount of propane dispatched, or 8.5 MMCF of refill per day assuming 50 propane deliveries per day. At that rate it would take Boston Gas about eight days to refill its Everett propane storage.

45/We note that in Section III.C.3.d, *infra*, we order the Company to demonstrate the adequacy of its propane storage facilities.

Everett capable of storing 65.6 MMCF of propane and dispatching 40.0 MMCFD of SNG[46] and 40.0 MMCFD of propane air (Exh. BGC-2, Table G-14). In addition, Boston Gas can store a total of 113.5 MMCF and dispatch a total of 72.9 MMCFD of propane air from ten smaller propane facilities at various locations around the Company's distribution system (id.). To supply each of these facilities, Transgas trucks propane to them from Sea-3's Newington, NH propane terminal (id., Sec. One, p. 30; Exh. EFSC-80).

Boston Gas stated that it normally uses its propane-air plant at Everett as backup to its SNG plant (Exh. BGC-2, Sec. One, pp. 30, 32), although both the SNG and propane-air plants are available for production, both could be used on cold days, and both are available from a system supply standpoint (Exhs. EFSC-6 and EFSC-8).

ii. Arguments

The City argues that 73 MMCFD better reflects the Company's propane dispatch capability than does the 112.9 MMCFD total capability claimed by the Company (City Brief, p. 11). The City bases its argument on the Massachusetts Department of Public Utilities' ("DPU") findings in DPU 555 which the City believes indicated that Boston Gas operated its outlying propane-air facilities far below their design capacities despite the most severe emergency conditions in recent history (id., pp. 10-11).

Boston Gas asserts that the City unfairly compares operating conditions of well over five years ago with today's design day and design year requirements (Company Reply Brief, p. 7). To support its assertion, Boston Gas cites two changes at the Everett plant that indicate different conditions today than five years ago (id.).

iii. Analysis

In essence, Boston Gas treats its Everett propane-air plant the

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46/The Company makes SNG from propane feedstock (Exh. BGC-2, Sec. One, p. 30).

same way it treats standby vaporization capacity at Lynn and Salem -- as backup capacity to ensure a minimum Everett production capability of 40 MMCFD. Thus, the Siting Council finds that the Company's policies of maintaining the Everett propane-air plant as standby capacity for operating purposes, and of assuming the Everett propane-air plant could be available for supply purposes on very cold days are reasonable policies. Given those two policies, the total propane production capability claimed by the Company is 112.9 MMCFD with 40 MMCFD of standby capacity.

Based on the record, the Siting Council cannot conclude that the outlying facilities could not perform at rated capacities should the need arise. The Company stated that all propane-air production facilities are tested annually (Exh. EFSC-8). In addition, the outlying production facilities are operated primarily for peaking purposes of short duration, not for extended periods of time (Exh. BGC-2, Table G-22D-Load Duration Curve). Thus, the ability to operate at rated capacity for an extended period is not as critical for the outlying propane-air facilities as it is for other aspects of the supply plan such as Everett production capability, propane trucking capability, or liquefaction capability. In a future proceeding, however, the Company will need to demonstrate that all of its peakshaving facilities can operate at their rated capacities.

Condition Four, in part, ordered the Company to estimate the ability of its propane-air facilites to operate over the extended period of time required to dispatch 47.5 million gallons of propane. In addition, the Company was ordered to state the number of hours per day its propane facilities would be expected to operate, and the number of days as well as hours per day that customers could absorb the necessary level of propane sendout. The Company provided the following analysis:

> For the 1986-87 heating season, Boston Gas would require approximately 21 million gallons of propane to meet firm sendout requirements. In an effort to conserve LNG for peak shaving on the coldest days, the Company would most likely begin propane-air production at Everett on or about December 15th at a fixed amount, at a rate of approximately 30-40,000 MMBTU per day. The remaining propane quantity would be produced to meet peaking needs on very cold days as determined by sendout demand. (Exh. BGC-2, Appendix A, Response to Condition Four)

This analysis is deficient for several reasons. First, Condition Four ordered the Company to examine how it would dispatch 47.5 million gallons of propane. Second, the Company chose to analyze 1986-87 propane requirements of 21 million gallons (1,927 MDth) while the Company's estimated 1986-87 design year propane requirements as set forth in its forecast is 25 million gallons (2,317 MDth) (Exh. BGC-2, Table G-22D-original). The Company offerred no explanation for this discrepency. Finally, the Company increased its estimate of 1986-87 propane requirements to 33 million gallons (3,054 MDth) when it determined that it would not be receiving Boundary/INGS supplies (id., Table G-22D-revised). The Company, however, failed to re-analyze its dispatch plan based on the increased requirements.

Not only did the Company fail to analyze its ability to dispatch 47.5 million gallons, it also failed to estimate the number of hours per day its propane facilities would be expected to operate, and the number of days as well as hours per day that customers could absorb the necessary level of propane sendout. Accordingly, the Siting Council finds that Boston Gas failed to comply with Condition Four.

The Company also did not provide a basis for determining whether it could dispatch its 1987-88 design propane requirements of 36 million gallons. Accordingly, the Siting Council finds that the Company failed to establish that it could dispatch the propane requirements set forth in its 1986 forecast.

d. Conclusions

Boston Gas has not demonstrated its ability to transport and dispatch the quantities of propane that its own base case supply plan indicates it will need in a design year. Therefore, to determine the adequacy of the Company's supply plan, the Siting Council examines the supply plan under the contingency that the Company cannot dispatch Everett propane on a design day.

The Siting Council orders Boston Gas to present in its next forecast filing 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. The Company is further ordered (1) to estimate, and provide a detailed analysis of, its maximum ability to use propane given all the procurement, storage, and dispatch constraints, (2) to identify the critical factor(s) determining that maximum amount, and (3) to provide propane dispatch sensitivity analyses for a reasonable range of estimates for such critical factor(s). In addition, the Company is ordered to justify any terminalling rights at Sea-3's Newington, NH propane terminal above the Company's maximum ability to use propane as a supply.

D. Adequacy of Supply

1. Base Case Analysis

In reviewing Boston Gas' supply plan, the Siting Council must determine whether the Company has adequate resources to meet projected sendout requirments under a reasonable range of contingencies. In order to make this determination, the Siting Council examines whether the Company's "base case" resource plan is adequate (1) to meet firm sendout requirements under normal year, design year, design day, and cold snap weather conditions, and (2) to meet those firm sendout requirements under a reasonable range of contingencies. Berkshire Gas Company, EFSC 86-29, p. 22 (1987).

If the Siting Council determines that the Company's base case plan is not adequate to meet projected sendout under a reasonable range of contingencies, the Company must establish that it has an action plan to meet those firm sendout requirements. Id.

Although the Siting Council previously found that the Company's forecasts of normal year, design year, and design day sendout requirements are not reliable (see Section II, supra), those forecasts serve as the only available bases for judging the Company's supply preparedness, and therefore the Siting Council will use them in its review of supply adequacy.

a. Design Year[47]

In design year planning, Boston Gas must have adequate supplies to meet several types of requirements. Above all, Boston Gas must meet the requirements of its firm customers. In addition, the Company must ensure that its storage facilities are filled prior to the start of the heating season. To the extent possible, Boston Gas also supplies gas to its interruptible customers.

The Company provided its design year supply plan in Table G-22D of its forecast filing (Exh. BGC-2, Table G-22D). This table indicated that the Company would have adequate supplies to meet its forecasted design year requirements. However, the Siting Council found in Section III.C.2.c, supra, that, for a design year, Boston Gas has not demonstrated its ability to refill the requirements of its LNG storage facilities as indicated in Table G-22D-LNG.

Accordingly, the Siting Council finds that Boston Gas has failed to establish that its base case supply plan is adequate to meet its forecasted design year sendout requirements.

b. Design Day

Boston Gas must have adequate supply capability to meet the requirements of its firm customers on a design day. While the total supply capability necessary for meeting normal and 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 firm pipeline gas and the maximum rate at which supplementals may be dispatched. Design day supply capability is also determined by the ability of a company's distribution system to meet design sendout rates. The Siting Council examines the ability of the Company's distribution system to meet design sendout rates in Section III.F, infra.

The Company presented its design day supply plan in forecast

47/In this case, the Siting Council makes no findings regarding normal-year adequacy.

Table G-23 (Exh. EFSC-14). Table 7 summarizes the Company's five-year design day supply plan, as presented in Table G-23 and modified for the Siting Council's findings herein, and compares that supply plan to the Company's forecasted design day requirements. Table 7 indicates that the Company would have adequate supplies to meet its forecasted design day requirements.

The Siting Council, however, reserves its finding on the adequacy of the Company's design day supply plan until it analyzes the adequacy of the Company's distribution system. See Section III.F.3.c.ii, infra.

c. Cold Snap

As part of Condition Nine of its last decision, the Siting Council ordered Boston Gas to submit an analysis of its cold snap preparedness to demonstrate that it would be able to meet its firm sendout obligations throughout a protracted period of design or near-design weather. Boston Gas Company, et al., EFSC 84-25, pp. 47, 50 (1986). The Siting Council has defined a cold snap as a prolonged series of days at or near peak conditions. Berkshire Gas Company, EFSC 86-29, p. 25 (1987). A company must demonstrate that the aggregate resources available to it are adequate to meet the 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.

As its cold snap analysis, the Company filed a load duration curve for a 1986-87 design heating season (Exh. BGC-2, Table G-22D-Load Duration Curve; Exh. EFSC-37; Tr. 5/6/87, pp. 50-52). This load duration curve is simply a reordering of the days in a design heating season that allows the Company to analyze design conditions if the coldest days occurred consecutively (Tr. 5/6/87, p. 51). This reordering allows the Company to examine such factors as its propane requirements (id.).

In addition, Boston Gas submitted an analysis of its preparedness during 1986-87 to meet a DD pattern actually experienced during the period February 9-18, 1979, in which more than 50 DD occurred each day for ten straight days (Exh. EFSC-37). The total number of DD for this ten-day period is 555 which compares with 476 DD for the coldest ten-day period in the Company's design year DD pattern (id.; Exh. BGC-2, Appendix B, Design Year DD Table). The analysis indicated that the Company would dispatch all of its contracted pipeline deliveries each day and supply the remaining requirements with propane and with LNG from each of its major LNG facilities (Exh. EFSC-37).

The Company has provided sufficient evidence establishing its ability to meet cold snap requirements during the 1986-87 heating season. Accordingly, the Siting Council finds that Boston Gas has complied with that part on Condition Nine requiring it to demonstrate its ability to meet a cold snap. To assure the Company's continued 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.

2. Contingency Analysis

In determining the adequacy of a company's supply plan, the Siting Council identifies certain key contingencies and evaluates the impact on the company's ability to meet forecasted requirements if such contingencies occur. For example, a company has to demonstrate that it has adequate resources to meet projected firm sendout requirements, even if certain existing resources were unavailable due to delivery problems or if certain planned new supplies were delayed or cancelled.[48] If a company cannot establish that it has adequate resources in the event that certain identified resources are not available, it must then demonstrate that it has an action plan to meet sendout requirements in the absence of those resources.

In the case of Boston Gas, the Siting Council's discussion and findings in Section III.C herein have raised a number of concerns about the Company's ability to document the existence of certain new supplies. The Siting Council previously found that Boston Gas' supply

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48/In the instant case, the Siting Council's contingency analysis focuses on the Company's ability to meet design day sendout requirements since the Siting Council has already found in Section III.D.1.a, supra, that the Company has not established that it has an adequate base-case, design-year supply plan.

plan should consider two contingencies: the delay or unavailability of the Alberta Northeast project, and the failure of Boston Gas to establish that it could place a new 40 MMCFD vaporizer in service on schedule (see Sections III.C.1.b.ii and III.C.2.b.ii, supra). Other uncertainties, however, also affect the supply plan. Therefore, to evaluate the adequacy of the Company's supply plan, the Siting Council analyzes four separate contingencies, each with the additional assumption that the Alberta Northeast project and the new 40 MMCFD vaporizer are both delayed beyond the five-year forecast horizon:[49] (1) no DOMAC vaporization during the 1986-87 heating season; (2) delay by one year of construction of the new Commercial Point vaporizer; (3) delay in the NOREX project beyond the forecast period; and (4) the inability of the Company to use its Everett propane plant in any year.[50]

a. Action Plan Options

Boston Gas identified three options available to it in the event of contingencies: (1) reduce its sales forecast by curtailing anticipated load; (2) contract for an additional source of supply; and (3) increase its use of existing peakshaving facilities (Exh. EFSC-17; Tr. 1/5/87, pp. 123-124).

As a matter of public policy, curtailing load growth may be an acceptable option in the event of emergencies or sudden supply shortages, but is undesirable as a result of inadequate supply planning. If a company's analysis and forecasts show that new load growth has benefits to customers and to the company, then that company should ensure that its supply planning process is capable of providing

49/The Company asserted that contingencies have already been built into the design day sendout forecast by planning for the worst possible case (Tr. 1/5/87, pp. 124-125; Exh. COB-8).

50/The Siting Council examines each of these contingencies, except for the DOMAC contingency, beginning with the 1987-88 heating season. While the 1986-87 has already past, we examine the DOMAC contingency to determine whether the Company's supply planning process was capable of adapting to that scenario.

adequate resources to accommodate such growth.

With respect to contracting for an additional source of supply, the Company has provided no indication that it would be able to add such a supply within the forecast period (Tr. 1/5/87, pp. 123-124). Thus, the Siting Council finds that the option available to Boston Gas under its action plan is increased use of peakshaving facilities. All of the Company's peakshaving capability, however, is already included in the Company's base case supply plan summarized in Table 7.

b. DOMAC

In Condition Eight of its last decision, the Siting Council ordered Boston Gas to file a design day contingency plan for the event that DOMAC supplies are not available. The Company filed its supply plan without including DOMAC supplies (Exh. BGC-2, Table G-23; Exh. EFCS-14), and therefore the Siting Council finds that Boston Gas complied with Condition Eight. At the same time, however, the Company indicated the availability of DOMAC vaporization as standby capacity for backing up the Company's 1986-87 design day supplies (see Section III.C.2.b.i, supra).

If all other resources in its base-case supply plan were available to Boston Gas,[51] absence of DOMAC standby vaporization would not cause a supply deficiency (see Table 8). Accordingly, the Siting Council finds that Boston Gas has established that it had adequate supplies to meet its forecasted requirements in the event that DOMAC vaporization capacity was not available for meeting a 1986-87 design day.

c. New Commercial Point Vaporizer

The Company plans to place a new 62.5 MMCFD vaporizer in service by December 1, 1987 (see Section III.C.2.b.ii, supra). If all other

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51/The unavailability of the Alberta Northeast project and the new 40 MMCFD vaporizer do not affect the 1986-87 heating season.

resources in its base-case supply plan were available to Boston Gas,[52] delay by one year of this new vaporizer would not cause a supply deficiency (see Table 8).

Accordingly, the Siting Council finds that Boston Gas has established that it has adequate supplies to meet its forecasted requirements in the event that its new 62.5 MMCFD Commercial Point vaporizer is not available for meeting a 1987-88 design day.

d. NOREX

The Company plans to add a new supply, known as the NOREX project, at an MDQ of 43.6 MMCFD prior to the 1989-90 heating season (see Section III.C.1.b.iii, *supra*). If all other resources in its base-case supply plan were available to Boston Gas, except the Alberta Northeast project and the new 40 MMCFD vaporizer, a two-year delay in the NOREX project would not cause a supply deficiency (see Table 8).

Accordingly, the Siting Council finds that Boston Gas has established that it has adequate supplies to meet its forecasted requirements in the event that the NOREX and Alberta Northeast projects as well as the new 40 MMCFD vaporizer are delayed beyond the forecast horizon.

e. Everett Propane Plant

The Company has not sufficiently demonstrated its ability to truck propane given its limited storage facilities (see Section III.C.3.b.iii, *supra*). If all other resources in its base-case supply plan were available to Boston Gas, except the Alberta Northeast project and the new 40 MMCFD vaporizer, the inability of the Company to use its Everett propane plant would not cause a supply deficiency (see Table 8).

Accordingly, the Siting Council finds that Boston Gas has established that it has adequate supplies to meet its forecasted

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52/The unavailability of the Alberta Northeast project and the new 40 MMCFD vaporizer do not affect the 1987-88 heating season.

requirements without its Everett propane plant, the Alberta Northeast project, and the new 40 MMCFD vaporizer.

3. Conclusions

The Siting Council finds that Boston Gas has adequate resources to meet its forecasted requirements in its base-case supply plan and under a reasonable range of contingencies.

At the same time, however, our contingency analysis raises new questions about the Company's supply planning process. Since the level of production reserve available to Boston Gas is over 11 percent in every forecast year, the Company has little need for base resources in excess of its firm requirements (see Table 7). Boston Gas itself asserted that maintaining as little as 0.95 percent of excess base resources is sufficient as long as standby vaporization and propane production are available as reserve (Tr. 1/5/87, p. 129). Yet Boston Gas plans to add two projects -- the Alberta Northeast project and a new 40 MMCFD LNG vaporizer -- to its base resources that increase reserve margins to over 20 percent (see Table 7). Boston Gas has provided no justification for design day reserve margins of 20 percent or more. Therefore, the Company not shown that these two projects are needed to meet firm requirements.

Accordingly, the Siting Council finds that Boston Gas has failed to establish that either the new 40 MMCFD LNG vaporizer or the Alberta Northeast project are needed for adequacy purposes to meet its forecasted firm requirements.[53]

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[53] In Section III.E, infra, the Siting Council will evaluate whether the Company established need for either the new 40 MMCFD vaporizer or the Alberta Northeast project based on least-cost supply planning.

E. Least-Cost Supply

In determining whether Boston Gas' supply plan is least cost, the Siting Council examines the assumptions and considerations that the Company uses both in determining sendout requirements and in deciding how to meet those requirements.

1. Least-Cost Planning Process

Throughout this proceeding, Boston Gas asserted that its assumptions, methodologies, and decisions ensure that it will meet sendout requirements in a least-cost manner. For example, in her testimony on the Company's choice of its design year standard, Ms. Michalek asserted that the Company "works within the bounds of least cost supply planning" (Tr. 1/14/87, p. 127) In response to the Siting Council's request that the Company support this assertion by discussing the Company's least-cost planning process and explaining how that process meets the Siting Council's least-cost planning mandate, the Company provided the following statement:

> Boston Gas is committed to providing a reliable energy source to its customers at the lowest possible cost. It accomplishes this through, among other things, efficient supply planning and dispatching.
>
> The Company feels confident that its supply planning methodologies effectively meet the "least-cost" planning mandate of the Siting Council. (Exh. EFSC-50)

This response demonstrates the Company's indifference to the Siting Council's statutory obligations to ensure adequate supplies at the lowest possible cost. The Company made assertions without providing any support, reasoning, or documentation which would allow the Siting Council to evaluate the Company's conclusions. As these sorts of "assurances" do not constitute evidence, the Siting Council finds this response to be entirely unreviewable.

In other instances, the Company similarly failed to establish that its planning process results in least-cost supply. The Company asserted in its forecast that in deciding which supplies to use to meet its requirements, it balances "sendout requirements with available supplies in a least cost manner" (Exh. BGC-2, Sec. One, p. 21). In addition, Ms. Michalek testified, in reference to the Company's choice of design planning standards, that it "is aware of the cost of being overconservative" (Tr. 1/14/87, p. 128). The witness further testified, regarding the Company's propane transportation limit, that "there is a price paid for overcapacity" (id., p. 172). At no time in the proceeding, however, did the Company provide any information which documented any of these assertions.

The Siting Council previously found (see Sections II.C.2.e and II.C.2.f, supra) that the Company's choice of its design year and design day standards is not based on any consideration of cost. The Company makes its supply planning decisions based on forecasts derived from these standards. Absent information about the costs implied by these standards, the Siting Council is unable to determine whether the supply plans based on these forecasts are least cost.

Accordingly, the Siting Council finds that the Company has failed to establish that it has a planning process that ensures that its assumptions, methodologies, and decisions result in a least-cost supply plan.

2. New Supplies

The Siting Council recently articulated its concerns regarding the need for gas companies to engage in least-cost planning. In its Order in EFSC 85-64, 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 the 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 needs, since options with similar reliability may have different costs and vice versa, and since different load additions with varying gas usage patterns impose different kinds of supply obligations in terms of cost.

In its most recent decision regarding Boston Gas, the Company was ordered to comply with the Siting Council's Decision in EFSC 85-64 and its implementation in Administrative Bulletin 86-1. Specifically, to enable the Siting Council to ensure that the Company's supply plan minimizes cost, the Company was ordered, as part of Condition Nine, to perform an internal study comparing the costs of a reasonable range of practical supply alternatives in the event that its filing indicated the addition of a long-term firm gas supply contract. Boston Gas Company, et al., EFSC 84-25, pp. 47-48, 50 (1986).

a. Boundary and Alberta Northeast

In the instant case, the Company's decision to add Boundary and Alberta Northeast volumes during the five-year forecast period triggered the need for such studies. The Company did not provide the required cost studies for either the Boundary or Alberta Northeast projects (Exhs. EFSC-51 and EFSC-111; Tr. 5/15/87, pp. 47-51). Accordingly, the Siting Council finds that Boston Gas has failed to comply with a direct Siting Council order as well as that portion of Condition Nine requiring the performance of cost studies. Further, the Siting Council finds that the Company has failed to establish that the Boundary and Alberta Northeast projects represent least-cost additions to the Company's supply plan.

This failure to provide cost studies for supply additions raises serious questions about the Company's ability to make informed, cost-justified supply planning decisions. Ms. Michalek testified that in the past she had performed analyses supporting the Company's decision to select the Boundary project (Tr. 5/6/87, p. 24), but had no documentation of such studies (Exh. EFSC-111; Tr. 5/6/87, p. 24; Tr. 5/15/87, pp. 47-51). Lack of documentation is particularly alarming for a Company the size of Boston Gas: the Siting Council requires the largest utilities in the Commonwealth to demonstrate that their supply choices are based on rational, well-thought-out cost and reliability comparisons with other available alternatives. 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.

The Siting Council found in Section II.D.3, supra, that the Company failed to establish that the Alberta Northeast project is needed to ensure adequate supply for meeting firm requirements. Although it is possible to establish need for new supplies or facilities by demonstrating that such new supplies or facilities reduce customer costs and thereby contribute to a least-cost supply plan, the Company failed to demonstrate that the Alberta Northeast project would have this effect on costs. Accordingly, the Siting Council finds that Boston Gas has not established that it should add its proposed Alberta Northeast supply.

b. NOREX

The Company's intent to add NOREX volumes during the five-year forecast period also triggered the need for a cost-study. In response, the Company submitted an internal memorandum describing the costs and advantages of the project (Exh. EFSC-110). The Company's response has raised serious questions regarding the least-cost nature of its decision since the Company's cost study failed to consider several critical factors.

In terms of the scope of alternatives, the analysis examined only the proposed project and one alternative course of action -- using more propane -- even though the Company stated that other identified pipeline supplies do, in fact, constitute alternatives (Exh. EFSC-110; Tr. 5/15/87, p. 46). Regarding the viability of the propane supply alternative, Ms. Michalek testified that propane constraints would cause the Company to discontinue its load growth plans unless it obtained NOREX supplies (Tr. 5/15/87, p. 34) -- that is, propane is not a viable alternative.[54] Not only did the Company fail to compare NOREX to identified alternatives, it failed to compare NOREX to any viable alternatives. Accordingly, the Siting Council finds that the Company's cost study fails to consider a reasonable range of practical supply alternatives.

54/The Company's response to the Siting Council's order in Section III.C.3.d, supra, should establish any constraints on Company propane use providing a guideline for future supply planning.

In terms of how the Company analyzed its options, many important considerations were not included in the analysis. First, various fixed and variable costs of the presented options, such as operating and maintenance costs, propane terminalling services, and trucking commitments, were left out of the analysis (Exh. EFSC-110; Tr. 5/15/87, pp. 24-25). This omission in the design of a study that compares a new option with use of an existing resource is problematic since each type of supply has different combinations and types of avoidable costs.

Second, the analysis did not discuss the direct financial implications of the two options on customer rates (Exh. EFSC-110; Tr. 5/15/87, pp. 31-33). Third, the Company's analysis included no sensitivity analyses showing how delays in the project, changes in fuel price assumptions, or changes in load growth assumptions would affect relative costs (Exh. EFSC-110; Tr. 5/15/87, pp. 29, 35-41). Fourth, the Company provided no analyses showing how the Company determined the best MDQ and ACQ (Exh. EFSC-110; Tr. 5/15/87, p. 35). Fifth, the weather database used in the study for the years 1919 through 1986 (Exh. EFSC-110) was not only inconsistent with the one used as a basis for the sendout forecast (i.e., 1923 through 1973) but also subject to many of the same problems discussed in Section II.C.2.b., supra. Finally, the analysis included no clear analysis of the tradeoffs between cost and reliability, a particular concern in that the Company chose NOREX in spite of the Company's analysis showing that the NOREX project is $1.1 million to $4.5 million per year[55] more expensive than the alternative of using more propane (Exh. EFSC-110; Tr. 5/15/87, p. 27). While Ms. Michalek stated that other Boston Gas departments addressed many of these considerations (Tr. 5/15/87, pp. 32-33), the only cost study in the record failed to adequately consider them.

Based on the record, the Siting Council finds that the Company

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55/ Since the Company did not model propane fixed costs (Tr. 5/15/87, pp. 24-25), the record does not contain a complete analysis of either the annual or life-cycle cost to Boston Gas customers of the Company's decision to select NOREX rather than propane. However, Ms. Michalek stated that propane fixed costs would be "about a nickle" per Dth (Tr. 5/15/87, p. 25). Based on that testimony, the annual cost of NOREX would be about $1.1 million more than propane.

has failed to establish that NOREX represents a least-cost addition to the Company's supply plan.

c. New 40 MMCFD LNG Vaporizer

The Siting Council found in Section III.D.3, supra, that the Company failed to establish that the new 40 MMCFD LNG vaporizer scheduled to be in service by November 1, 1988 was needed to meet customer requirements. Although it is possible to establish need for new supplies or facilities by demonstrating that such new supplies or facilities reduce customer costs and thereby contribute to a least-cost supply plan, the Company failed to demonstrate that the proposed vaporizer would have this effect on costs. Accordingly, the Siting Council finds that Boston Gas has not established that it should add a new 40 MMCFD vaporizer to its system supply.

3. Comparison of Alternatives on an Equal Footing

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 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 plan minimizes cost, the Siting Council also evaluates whether the company's supply planning process adequately considers alternative resource additions, including demand-side options, on an equal basis. Berkshire Gas Company, EFSC 86-29, p. 33 (1987); Fall River Gas Company, 15 DOMSC 97, 115 (1986).

In this case, 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. The Company stated simply that it supports conservation activities through the educational and audit services offered by MASS-SAVE (Exh. EFSC-4).

The Siting Council finds that the Company's supply plan fails to establish whether conservation and load management are reliable or cost-justified means of marginally reducing sendout during different seasons of the year, as an alternative to adding new supplies to meet these marginal sendout requirements.

Accordingly, the Siting Council finds that the Company has failed to establish that it treats all resource options on an equal footing in its planning process, since that process fails to incorporate conservation and load management.

4. Conclusions

Based on the foregoing, the Siting Council finds that the Company has failed to establish that its supply planning assumptions, methodologies, and resulting supply decisions ensure that the Company's supply plan minimizes costs subject to trade-offs with adequacy of supply.

F. Adequacy of Distribution System Planning

1. Description

Boston Gas distributes gas supplies to its customers through a network of gas mains in the 74 cities and towns that the Company serves. In this proceeding, the Company illustrated the performance of its distribution system through network analysis studies[56] of three Boston Gas districts, Central, West, and South[57] (Exhs. EFSC-26, EFSC-59, EFSC-60, and EFSC-61).[58] Review of these network analyses (in particular those for the Central District) in conjunction with other evidence regarding the Company's supply plan raised two new issues regarding the ability of its distribution system to adequately distribute the supplies necessary to meet forecasted requirements: (1) the Company's operation of its distribution system above its maximum

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56/Boston Gas staff studies or analyzes the performance of its distribution system under certain assumed conditions using a technique commonly known as "network analysis" (Exh. EFSC-54).

A network analysis study requires an accurate description of the distribution system being modeled, a reliable representation of the loads that must be supplied by that system, and a process capable of determining how the distribution system would supply those loads. Typically, the determination of how those loads are supplied is made by a computer program which "balances" distribution system pressures and flows based on gas flow equations. Knowledge of system constraints and operation helps determine whether the results of the computer study realistically reflect actual field conditions.

57/The Central District is roughly a triangular area bounded by Everett, Wellesley/Newton, and Milton/Quincy (Exh. EFSC-26). The West District is also roughly a triangular area bounded by Groton, Weston, and Burlington (Exh. EFSC-60). The South District includes the towns of Braintree, Weymouth, Hingham, Hull, Cohasset, Abington, Rockland, and Whitman (Exh. EFSC-61).

58/ The Company requested that the network analysis studies, specifically the "computer runs [i.e., studies] and the node maps that accompanied them" for the Central, West, and South Districts contained in Exhibits EFSC-59, EFSC-60, and EFSC-61, respectively, receive protective treatment (Tr. 7/1/87, pp. 15-16). The City did not object to this request (Tr. 7/1/87, p. 15). Accordingly, the Hearing Officer granted the request and placed the computer runs and node maps contained in Exhs. EFSC-59, EFSC-60, and EFSC-61 into a sealed record (Tr. 7/1/87, pp. 15, 24).

allowable operating pressure ("MAOP"), and (2) the Company's use of a different reliability standard for distribution system planning than for supply planning.

a. Background

Boston Gas had asserted that it could rely on standby vaporization at Commercial Point during the 1986-87 heating season because DOMAC vaporization at Everett provided an adequate backup (see Section III.C.2.b, supra). To support this assertion, the Company provided two schematic diagrams of its Central District intermediate pressure distribution system ("Central District IP system") summarizing the results of network analysis studies for two cases where, on a 65 DD peak hour during the 1986-87 heating season, the Company relied on standby vaporization at Commercial Point ("Diagram 1"), and the Company did not rely on standby vaporization at Commercial Point ("Diagram 2") (Exh. EFSC-26; Tr. 1/14/87, pp. 38-39).

Diagram 2 indicated that, if the Company needed to shut down one of its Commercial Point vaporizers under such peak conditions, the Company could shift some of its Algonquin volumes from the Company's Everett take station to the Company's Ponkapoag take station providing effectively the same volume and location of supply to the Central District IP system as was indicated in Diagram 1 (Exh. EFSC-26; Tr. 1/14/87, p. 44). Ms. Michalek stated that the Company has the contractual rights to direct Algonquin to shift its pipeline deliveries as indicated in the two diagrams (Tr. 1/14/87, pp. 44-45). Diagrams 1 and 2 indicated that the operation of the Central District IP system would be virtually identical under the two scenarios (Exh. EFSC-26).

The Company's response in Exh. EFSC-26 raised the two new issues.

b. Maximum Allowable Operating Pressure

Boston Gas classifies the Central District IP system as "intermediate pressure" (Exhs. EFSC-26 and EFSC-59; see also Tr. 5/15/87, pp. 55, 60-61), which the Company defined as "Systems which are normally operated at pressures greater than 10-inches wc [water column] but not greater than 13 PSIG" (Exh. EFSC-57). Ms. Michalek stated that the MAOP of this system is 13 pounds per square inch gauge ("psig") (Tr. 1/14/87, p. 30), and, upon further analysis of its Central District IP system, the Company verified the 13 psig MAOP (Exh. EFSC-59; Tr. 5/15/87, p. 100).

The Company indicated that there are effectively three points where it supplies the Central District IP system: Commercial Point, Everett, and Wellesley (Exh. EFSC-26). To operate the Company's distribution system as shown in Diagram 1,[59] Ms. Michalek testified that Boston Gas would have to supply gas to the Central District IP system at a pressure of 15 psig at Commercial Point, 12 psig at Everett, and 17 psig at Wellesley (Tr. 1/14/87, p. 35). Although Exh. EFSC-26 indicated that Boston Gas would need to exceed the Central District IP system MAOP in the vicinity of Commercial Point and Wellesley, Ms. Michalek stated that "we consider it to still be working within the maximum capabilities of our distribution system" (Tr. 1/14/87, p. 38), and she asserted that the system pressures around Commercial Point and Wellesley drop fairly quickly (id., p. 36).

In discussing the historical operation of the Central District IP system, Ms. Michalek provided the following:

> [T]here have been instances where we have gone, just recently, the past five years, have gone as high as 14 or 15 pounds [psig]. In talking yesterday, there was an instance 20 years ago where that particular portion of Wellesley pipe was 15 pounds. I don't know the exact date or the exact pressures, but we discussed it internally and stated that under the most severe operating conditions that the system could withstand 17 pounds at Wellesley. (Tr. 1/14/87, p. 37)

Ms. Michalek noted that the Company would "notify the proper authorities if there was an emergency situation and we had to go severely above maximum operating pressures, although nothing requires us to do so" (id., p. 58; see also pp. 37-38). Mr. Gilfeather, who testified on

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59/The Siting Council's discussion here focuses on Diagram 1. We note, however, that since the Central District IP system network analysis results are the same in Diagrams 1 and 2, a discussion of Diagram 2 would be similar to our discussion of Diagram 1.

behalf of Boston Gas regarding its distribution system, stated that he was unfamiliar with regulations governing the operation of the distribution system, but that "It's my understanding of the code that there is a provision in there that permits emergency operation to exceed normal operating pressures" (Tr. 5/15/87, pp. 101-102).

In a letter dated June 30, 1987, the Company stated that it operates its distribution system in compliance with applicable United States Department of Transportation ("DOT") and Massachusetts DPU regulations, 49 CFR 192 (Minimum Federal Safety Standards) and 220 CMR 100, respectively[60] (Exh. EFSC-116). DOT regulation 49 CFR 192.621(a)(5) provides:[61]

> Maximum allowable operating pressure: High-pressure distribution systems.
> (a) No person may operate a segment of a high-pressure distribution system at a pressure that exceeds the lowest of the following pressures, as applicable:
> ....
> (5) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressures. (Exh. EFSC-116)

Massachusetts DPU regulations as set forth in 220 CMR 101.06(19) incorporate by reference the federal standard contained in 49 CFR 192.621 (Exh. EFSC-116).

While citing these regulations, the Company provided the following:

60/Prior to that letter, which was filed one day before the close of the record on July 1, 1987, the Company had maintained that "As far as exceeding maximum operating pressures, the company does have internal standards that were [sic] governed under; however, as far as external standards, the company knows of none" (Tr. 1/14/87, p. 57).

61/The Siting Council notes that DOT regulation 49 CFR 192.3 provides that "'High pressure distribution system' means a distribution system in which the gas pressure in the main is higher than the pressure provided to the customer." As such, the Company's Central District IP system falls within this category.

> Boston Gas, however, has established internal gas operations standards with stated MAOP's that are lower than the standards permitted under the DOT and DPU regulations. Under normal conditions, Boston Gas operates its distribution system at pressures lower than allowed by DOT and DPU standards. In the event that it becomes necessary to temporarily raise the pressure above Boston Gas' own internally set MAOP, Company policy requires that notification be given, and approval secured, from Senior Management. Again, however, these are Company standards that may be revised at will subject only to the MAOP of the system as ascertained by the DOT code. (Exh. EFSC-116)

The Company added that its Central District IP system "internally set MAOP" became effective on January 3, 1978 (Exh. EFSC-116). Boston Gas also stated that the MAOP of this system under DOT/DPU regulations is 22 psig although the Company did not indicate when that standard was set (id.).

c. 65 Degree Day Planning Standard

Whereas gas companies' supply plans are designed to meet peak requirements in terms of a design day, gas distribution systems are designed to meet peak requirements within that design day. Boston Gas designs its distribution system to meet a peak or design hour flow on a design day (Exhs. EFSC-58, EFSC-59, EFSC-60, and EFSC-61).

Boston Gas has set its design day supply planning reliability standard at 73 DD and its distribution system reliability standard at the peak hour of a 65 DD (Exh. BGC-2, Table DD; Tr. 1/14/87, pp. 38-39, 146-147; Exhs. EFSC-53, EFSC-55, EFSC-58, EFSC-59, EFSC-60, and EFSC-61; Tr. 5/15/87, pp. 112-114). Ms. Michalek provided the Company's justification for maintaining a dual standard:

> If we were to run out of supply, which we think we have proven we have the capability not to run out of supply on a 73-degree day day, the whole system would be lost. On ... a 73-degree day day, if we lost a certain portion of the system because of failure of our distribution system, it would not be as critical, compared to complete loss of supply. That is why there are two different standards. (Tr. 1/14/87, p. 38)

To further explain, Boston Gas provided the following statement:

> It is possible to restrict a supply outage to a section of the Boston Gas service territory. However, given the variables involved, including but not limited to station MDQ's, production capacity and distribution system operating constraints, managing a supply outage of any kind would require extreme coordination among distributor, pipeline and production personnel. An outage due to insufficient distribution system capacity on extremely severe days can be localized and minimized much more easily than shortfall of supply and is within the complete control of Boston Gas Company. (Exh. EFSC-53)

Ms. Michalek identified the supply factors outside the Company's control as the Company's two pipeline suppliers (Tr. 5/15/87, p. 98).

Ms. Michalek asserted that an outage due to insufficient distribution system capacity ("distribution outage") would be easier to control than an outage due to insufficient supply ("supply outage") because the low pressure points on the system would be staffed thereby providing "more information to make decisions," although she added that there is nothing physically that field personnel could do to improve the pressures (Tr. 5/15/87, pp. 106, 109). In contrast, she said, in the event of a supply shortage the Company could not staff "the kind of areas that I am talking about throughout the system," although she did not identify the size of the "kind of areas" involved in a supply shortage (id., p. 109).

Boston Gas provided an "emergency response plan" for situations where the Company might not be able to meet its requirements (e.g., a supply shortage or a shortfall of distribution system capacity) (Exh. COB-24; Tr. 1/14/87, p. 20). This plan identified four sequential steps that could be implemented based on the severity of the emergency: (1) reduction or termination of interruptible customers; (2) reduction or termination of selected large volume customers; (3) reduction in use by all customers in the area, by requesting a cut back of thermostats or a reduction of non-essential uses; and (4) a specific area shutdown (Exh. COB-24; Tr. 1/14/87, p. 20).

In regard to implementation of the second step of the emergency response plan, Mr. Gilfeather stated that, if the Company had to terminate service to large volume customers due to insufficient distribution capacity, there may be preferences to terminate customers in those parts of the system where more capacity could be gained (Tr. 5/15/87, pp. 110-112). In the event of a supply shortage, however, Ms.

Michalek stated that "in a pure theoretical sense" there would not be a preference to terminate service to certain large volume customers based on their location (id.). Ms. Michalek, however, did not explain how the Company's actions in a practical sense would differ from those "in a pure theoretical sense" (id.).

While the Company stated that the 65 DD distribution criterion did not restrict the Company's ability to dispatch supplies on days colder than 65 DD, Boston Gas also noted that "very small select areas of Boston Gas' distribution system may need increased operating pressures or additional attention by Company personnel during periods of severely cold weather, including those days with greater than 65 DD" (Exh. EFSC-53). Boston Gas, however, could not provide any analysis indicating that it has the ability to distribute supplies on days colder than 65 DD (Exh. EFSC-53). When asked if the Company's assertion that it may operate its distribution system above MAOP when necessary was a reason why Boston Gas concludes that a supply outage would be a more serious problem than a distribution outage, Ms. Michalek responded "that is part of it" (Tr. 5/15/87, p. 105).

The Company, however, would not provide distribution system network analysis studies demonstrating the Company's ability to dispatch supplies on a 73 DD day since Boston Gas has successfully used the 65 DD standard as a distribution system design tool for approximately 30 years (Exhs. EFSC-55, EFSC-59, EFSC-60, and EFSC-61; Tr. 5/15/87, pp. 97-98).

2. Arguments

The City maintains that, given the serious consequences of an interruption in service, the standards of reliability must be extremely high (City Brief, p. 2). The City asserts that the Company's justification of different reliability standards for the distribution system and supply plan is not reassuring, and that, without a systematic analysis of the costs and benefits of the lower distribution system reliability standard, it is impossible to assess the acceptability of the current risk of a distribution failure (id., p. 16). The City also maintains that the Company must operate above MAOP and that, although there is not an adequate basis for determining the practical effects of such operation, this practice deserves careful evaluation (*id.*, pp. 16-17; City Reply Brief, p. 8).

Boston Gas agrees that the reliability of gas supplies to its customers is of paramount importance (Company Reply Brief, p. 3). Boston Gas asserts that it has shown that it has adequate facilities to meet design day requirements (*id.*). The Company argues, however, that it is appropriate to maintain dual standards of reliability for supply and distribution (Company Final Reply Brief, p. 2). From a supply standpoint, the Company maintains, there are no brownouts in the gas industry and therefore the Company must plan for the worst possible case, which the Company has identified as a 73 DD day (*id.*, p. 3). From a distribution standpoint, however, the Company maintains that the 65 DD standard has been used successfully for many years and does not limit the Company's ability to distribute supplies on colder days (*id.*).

Boston Gas also argues that there has been no allegation that the Company has not operated its distribution system in compliance with applicable federal and state regulations (Company Reply Brief, p. 12). In addition, the Company asserts that it has not had, and does not anticipate having, any distribution problems that would impede its ability to serve its customers (*id.*).

3. Analysis

a. Jurisdiction

The Company maintains that the Siting Council regulations do not require an analysis of the adequacy of the Company's gas distribution system (Company Reply Brief, p. 12). Therefore, the Company suggests that the Siting Council does not have jurisdiction to review the adequacy of the gas distribution system (*id.*, pp. 12-13; Company Final Reply Brief, p. 3).

In considering gas distribution system issues in the current review of the Company's long-range supply plan, the Siting Council is clearly fulfilling its statutory mandate of 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. The Siting Council's statute explicitly ties companies' ability to commence construction of facilities to Siting Council determinations as to whether those facilities are consistent with the most recently approved long-range forecast or supplement thereto. G.L. c. 164, sec. 69I.

Further, the Siting Council's broad statutory mandate clearly requires the Siting Council to review a company's ability, including through the distribution of gas, to meet design day as well as normal and design year gas requirements. Without an adequate distribution system, a company can not provide reliable and uninterrupted service to its customers. If the Siting Council were unable to review the adequacy of a company's distribution system, it could not in fact fulfill its mandate to ensure a necessary energy supply for the Commonwealth.[62]

Accordingly, the Siting Council finds that the consideration of the Company's gas distribution system is critical to a meaningful review of the Company's supply plan and, as such, falls squarely within the Siting Council's jurisdiction.

b. Maximum Allowable Operating Pressure

The record contains evidence of irregularities in the Company's determination of the MAOP of its Central District IP system. Boston Gas asserted that the MAOP of this system is 22 psig, but that the "internally set MAOP" is 13 psig. The Company provided certain sections of federal and state regulations that govern the operation of all distribution systems. The DOT and DPU regulations clearly intend that an "internally set MAOP" is to be considered the MAOP under federal and state regulations if the operator has determined that such an internally set MAOP is the maximum safe pressure of a distribution system.

While Boston Gas has asserted that the MAOP of the Central

62/The Siting Council notes that for electric companies, the Siting Council has addressed the issue of the adequacy of the transmission system in a proceeding where the company had proposed no jurisdictional facilities, Massachusetts Electric Company, et al., 15 DOMSC 241 (1986), as well as a case where a facility proposal had been severed from the complete filing in order to expedite a review. Boston Edison Company, 15 DOMSC 287 (1987).

District IP system is 22 psig, there is no evidence in the record to support this assertion. In fact, the record shows that Boston Gas has determined that the maximum safe pressure of the Central District IP system is the internally set MAOP, 13 psig.

Boston Gas classified the Central District IP system as an intermediate pressure system which the Company plans to operate at a pressure not greater than 13 psig. The Company cited only two instances in the last 20 years in which the Central District IP system exceeded 13 psig by operating as high as 15 psig. Boston Gas provided that, at Wellesley only, the system could withstand 17 psig "under the most severe operating conditions." Boston Gas has a policy requiring notification of the proper senior managers should the Company need to raise the pressure of its Central District IP system above 13 psig. Company staff responsible for gas dispatch and distribution planning were not even aware that the Company had set an internal MAOP separate from federal and state standards (Tr. 1/14/87, p. 57). All evidence in the record indicates that Boston Gas has determined the maximum safe pressure of the Central District IP system to be 13 psig.

While the Company has asserted that it may operate above MAOP if it so chooses (Tr. 5/15/87, p. 105), it has provided no evidence that it is allowed to do so under federal and state law. The very classification, "maximum allowable operating pressure," clearly sets forth that such pressure is not to be exceeded and serves as a basic distribution system planning assumption. If this term is not sufficiently clear to the Company, it need look no further than the term's definition in 49 CFR 192.3: "'Maximum allowable operating pressure' means the maximum pressure at which a pipeline or segment of a pipeline may be operated under this part." The risks of operating a distribution system at higher ratings are also obvious -- if a pipeline is not designed to withstand higher operating pressures, then exceeding MAOP creates the possibility of unsafe operating conditions or a catastrophic failure. Therefore, the Siting Council rejects any assertion by Boston Gas that it may, at will, disregard federal and state regulations and operate its distribution system above MAOP.

In addition, the Company provided no evidence indicating that there are regulatory provisions for allowing the Company to exceed its

MAOP under any sort of emergency. Even if the Company could provide such evidence, operating a distribution system at planned-for design conditions cannot be considered an emergency -- rather, design conditions are a planning standard that a Company must demonstrate that it has the ability to meet under base planning assumptions, and a base planning assumption is that MAOP must not be exceeded.

Accordingly, the Siting Council finds that (1) Boston Gas must design and plan its distribution system to operate at or below its maximum allowable operating pressure as set forth in 49 CFR 192 and 220 CMR 101, and (2) the MAOP of Boston Gas' Central District IP system under these regulations is 13 psig.

This finding raises new questions that cannot be answered by the record in this proceeding. In particular, the Company appears to require more than 13 psig at its Commercial Point LNG facility in order to dispatch design day volumes of LNG (Exh. EFSC-26). Such constraints may also impede the Company's ability to use its new vaporizer planned to be in service at Commercial Point by December 1, 1987 (see Section III.C.2.b.iii, supra). Thus, we order the Company to demonstrate in its next forecast filing 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.

c. 65 Degree Day Planning Standard

i. Dual Planning Standards

The Company provided four reasons justifying its use of 65 DD as a design standard for its distribution system instead of the 73 DD standard it uses for supply planning: (1) the 65 DD standard has been used successfully since the mid-1950s, (2) a supply outage would have more severe effects than a distribution outage, (3) a supply outage would be more difficult to control than a distribution outage, and

(4) if necessary, the Company can operate its distribution system above MAOP to provide more distribution capacity. In that we have already rejected the fourth reason, operation above MAOP, we now review the Company's other three reasons.

In regard to the Company's first contention, the fact that a practice that has been used successfully for approximately 30 years carries little weight in light of (a) the only day since 1943 to exceed 65 DD was the 68 DD day on January 15, 1957 (Exhs. BGC-1 and EFSC-36), and (b) Boston Gas plans its supplies to meet the coldest day ever experienced, a 73-DD day that occurred 53 years ago in 1934 (Exh. BGC-2, Table DD). Thus, the Siting Council finds that the Company's use since the mid-1950s of a 65 DD standard for distribution system design does not justify maintaining a lower reliability standard for the distribution system than for the supply plan.

In regard to the Company's second assertion, Boston Gas could not provide any analysis indicating how a supply outage would be any more detrimental to Boston Gas customers than a distribution outage. In fact, in either case, Boston Gas would need to terminate service to a certain number of customers in order to provide service to the remainder of its customers. Since the effect on customers would be identical, the Siting Council rejects the Company's assertion that a supply shortage would be more detrimental to customers than a distribution capacity shortage.

In regard to the third contention set forth by Boston Gas, the Company claimed that certain aspects of a supply outage would require "extreme coordination" (Exh. EFSC-53) since the Company's pipeline suppliers are "outside of our control" (Tr. 5/15/87, p. 98). This argument is perplexing. Boston Gas already coordinates deliveries with its two pipeline suppliers, Algonquin and Tennessee, every single day of the year (Exhs. EFSC-20, EFSC-21, and EFSC-22). Pipeline deliveries on a design day, when Boston Gas expects to use all of its pipeline supplies anyway, would be similar to deliveries on many other cold winter days (Exh. BGC-2, Table G-22D-Load Duration Curve). Therefore, coordination with pipeline suppliers on a design day should be closer to a routine practice than an operation requiring "extreme coordination."

In fact, a distribution outage may be more difficult to control than a supply outage. The Company correctly noted that there would be many factors to consider in determining which large volume customers to terminate first if conditions ever forced the Company to implement the second step of its emergency response plan (Exh. COB-24; Tr. 5/15/87, pp. 110-112). In the case of a supply outage, however, terminating any large volume customer located anywhere on the Boston Gas system would contribute equally (in proportion to the size of the customer) to reducing the extent of the outage, whereas in the case of a distribution outage, Boston Gas would have a preference to locate and terminate customers specifically in the parts of the distribution system where pressures are lowest. Therefore, the Siting Council finds that Boston Gas has failed to establish that a supply outage would be harder to control than a distribution outage.

Accordingly, the Siting Council finds that Boston Gas has failed to establish that designing its distribution system to a different standard of reliability than its supply plan is appropriate. The Siting Council orders 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.

ii. Adequacy of the Distribution System

While Boston Gas has demonstrated that it has adequate supplies, the Company must also demonstrate that it can distribute those supplies in order to be of any use to customers. Thus, Boston Gas' failure to support its use of dual planning standards leads directly to the question of whether the Company's distribution system -- planned as it is to a lower standard than the supply plan -- inhibits Boston Gas' ability to supply its customers' firm requirements on a design day.[63]

The Siting Council asked Boston Gas to provide studies that would

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63/Since we found in Section II.C.2.f, supra, that the Company had not determined its design day planning standard of 73 DD through an appropriate methodology, we use the Company's 73 DD standard in this discussion solely to evaluate the adequacy of the Company's distribution-system planning process.

demonstrate the Company's ability to distribute supplies on a 73 DD day. Boston Gas, however, would not provide any such studies, stating instead that the 65 DD distribution planning standard does not limit the Company's ability to distribute supplies on days colder than 65 DD, even though the distribution system "may need increased operating pressures or additional attention by Company personnel." The Siting Council has already rejected the Company's contention that it could increase operating pressures above MAOP, and the only "additional attention" provided by Company personnel would be information about field conditions -- little help if the gas mains in the ground are not sufficiently large to provide service to customers. It is certainly conceivable that the Company could serve some or all of its customers on days colder than 65 DD; however, Boston Gas has not demonstrated here that it can do so.

Boston Gas' lower reliability standard for planning its distribution system has effectively lowered the reliability standard of the Company's supply plan. Boston Gas has not demonstrated in any way that it can meet firm customer requirements on days colder than 65 DD. The failure of Boston Gas to plan its distribution system consistently with its supply plan has placed it in a position where it cannot ensure adequate service to firm customers on the coldest days of the winter when those customers need service the most.

Accordingly, the Siting Council finds that Boston Gas has failed to establish that its base case design day supply plan is adequate to meet its forecasted requirements.

4. Conclusions

Both the Company and the City assert that reliability of service to customers is of paramount importance and that the Company's standards of reliability must be extremely high. The Siting Council agrees that Boston Gas must plan to obtain and dispatch adequate supplies and to operate its gas distribution system in a way that ensures reliable and safe gas service to firm customers, especially under design weather conditions.

In this case, Boston Gas has failed to show that it is planning its distribution system consistent with safe operating assumptions and according to standards that would enable the Company to deliver fully the gas supplies the Company expects it would have to send out under design weather conditions. The Siting Council cannot accept the implications of this practice. To avoid unsafe operating conditions under worst-case weather, the Company would have to involuntarily terminate service to some set of firm customers -- something that would be technically difficult to do at best and which would have immeasurable adverse social and economic consequences at worst.

Elsewhere, the Siting Council has found that interrupting service to firm customers is unacceptable and violates the Siting Council's mandate to ensure an adequate supply of energy for the Commonwealth at minimum cost and minimum environmental impact. Boston Edison Company, 15 DOMSC 287, 333 (1987). Here, the Siting Council finds that Boston Gas' distribution system planning is flawed in this regard.

The seriousness of these findings cannot be overstated. Therefore, the Siting Council orders Boston Gas 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. Such a plan shall be filed by October 15, 1987. The Siting Council further orders Boston Gas to develop a long-term plan for reinforcing and redesigning its entire distribution system appropriate to a level of reliability equivalent to that assumed in the supply plan.

G. Summary

The Siting Council has found that Boston Gas failed to comply with Conditions Four and Five of the last Siting Council decision. In addition, the Siting Council has found that Boston Gas failed to comply with a direct Siting Council order as well as that portion of Condtion Nine requiring the performance of cost studies.

The Siting Council has already rejected the Company's forecast of sendout requirements. The rejection of a sendout forecast could arguably preclude the Siting Council from making any findings in regards to the adequacy and cost of a supply plan based on that forecast. We nevertheless focus our review of Boston Gas' supply plan on the Company's supply planning process to determine if that process would enable the Company ensure adequate supplies at least cost as well as enable the Company to make sound resource planning decisions.

The Company's planning process has failed on a number of grounds. Boston Gas has not demonstrated that it can refill its LNG storage facilities as would be necessary in a design year; the Company has not shown it has sufficient propane trucking capacity to meet its expected design year needs. In addition, the Company has not demonstrated that it has a planning process that results in a least-cost supply plan. Finally, the Company has relied on policies for planning and operating its distribution system that fail to ensure that the Company can meet its own forecasted design day requirements.

Accordingly, the Siting Council hereby REJECTS the Company's supply plan.

IV. DECISION AND ORDER

The Siting Council hereby REJECTS the sendout forecast and supply plan of Boston Gas Company and Massachusetts LNG, Inc. as presented in the Third Long-Range Forecast of Gas Requirements and Resources.

The Siting Council ORDERS Boston Gas Company 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, et al., EFSC 84-25 (1986);

2. (1) a re-evaluation of its Commercial Point and Lynn liquefaction capabilities that adequately considers historical liquefaction experience, (2) a demonstration that its re-evaluated 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 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;

5. a justification of any terminalling rights at Sea-3's Newington, NH propane terminal above the Company's maximum ability to use propane as a supply;

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; and

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.

The Siting Council FURTHER ORDERS the Boston Gas 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. Such a plan shall be filed by October 15, 1987.

The Siting Council FURTHER ORDERS the Company to file its next long-range forecast on September 1, 1988.

Frank P. Pozniak

Frank P. Pozniak
Hearing Officer

APPROVED by a majority vote of the Energy Facilities Siting Council by the members and designees present and voting. Voting for approval of the tentative decision as amended: Sharon M. Pollard (Secretary of Energy Resources); Elizabeth Kline (for James S. Hoyte, Secretary of Environmental Affairs); Dennis J. LaCroix (Public Gas Member). Voting against approval of the tentative decision as amended: Fred Hoskins (for Joseph D. Alviani, Secretary of Economic and Manpower Affairs); Timothy Gailey (for Paula W. Gold, Secretary of Consumer Affairs and Business Regulation). Abstaining: Joseph W. Joyce (Public Labor Member). Absent: Madeline Varitimos (Public Environmental Member); Stephen Umans (Public Electricity Member).

Sharon M. Pollard
Chairperson

14 September 1987
Date

TABLE 1

Boston Gas Company
Sendout Forecast by Customer Class[a]

Normal Year (MDth)

Class	1986-87 Heating Season	1986-87 Non-Heating Season	1990-91 Heating Season	1990-91 Non-Heating Season
Residential -- Htg	22,597	9,735	23,821	9,783
Residential -- Non-Htg	2,116	2,297	1,923	2,027
Commercial	13,815	7,091	16,624	7,895
Industrial	2,594	1,861	2,457	1,857
Wakefield	251	120	251	120
Company Use and UFG	4,146	(614)	4,233	(706)
Total Firm Sendout	45,519	20,490	49,308	20,976
Interruptible	0	6,733	0	11,366
Total Sendout	45,519	27,223	49,308	32,342

Design Year (MDth)

Class	1986-87 Heating Season	1986-87 Non-Heating Season	1990-91 Heating Season	1990-91 Non-Heating Season
Residential -- Htg	24,390	9,735	25,623	9,783
Residential -- Non-Htg	2,184	2,297	1,983	2,027
Commercial	15,091	7,091	17,818	7,895
Industrial	2,898	1,861	2,607	1,857
Wakefield	267	120	267	120
Company Use and UFG	5,713	84	5,371	(50)
Total Firm Sendout	50,543	21,188	53,669	21,632
Interruptible	0	6,733	0	11,366
Total Sendout	50,543	27,921	53,669	32,998

Notes

a. Totals may not add due to rounding.

Source: 1986 Forecast, Tables G-1 through G-5.

TABLE 2

Boston Gas Company
Firm Heating Sendout Regression Equation

Parameter	Parameter Estimate (Dth)	T Statistic	Probability[a]
DD	7955.7	6.82	.0001
DD * NOV	3468.1	5.25	.0001
DD * DEC	3950.8	5.85	.0001
DD * JAN	4287.4	6.35	.0001
DD * FEB	3844.2	5.67	.0001
DD * MAR	3534.7	5.23	.0001
DD * APR	1965.3	2.89	.0041
DD * MAY	1343.9	1.87	.0620
DD * OCT	2068.6	3.10	.0021
DD * DDRANGE1	-3999.5	-3.53	.0005
DD * DDRANGE2	-3762.4	-3.32	.0010
DD * DDRANGE3	-4093.4	-3.59	.0004
DD * DDRANGE4	-4254.1	-3.70	.0003
DD * DDRANGE5	-4527.5	-3.88	.0001
DD * COLD1	111.5	0.54	.5865
DD * COLD2	195.4	0.89	.3750

F Statistic = 1696.4 (Probability[b] = .0001)
Adjusted R^2 = .987
Durbin-Watson Statistic = 1.69

Notes

a. Probability that the parameter is not statistically significant.
b. Probability that the model is not statistically significant.
c. Baseload = 65,151 Dth
d. To determine sendout requirements for a given day, Boston Gas calculates heating sendout based on the equation above, adds gross or net load growth as appropriate, applies a four percent cold snap factor if appropriate, adds baseload, and, if necessary, adds requirements by Commonwealth. See Table 3 for a sample calculation.

Sources: Exhs. EFSC-27 and EFSC-30

TABLE 3

Boston Gas Company
1986-87 Design Day Sendout Calculation

Parameter	Parameter Estimate (MDth)	Contribution to 1986-87 Design Day[a] (MDth)
DD	7.9557	580.8
DD * JAN	4.2874	313.0
DD * DDRANGE5	-4.5275	-330.5
DD * COLD1	0.1115	8.14
DD * COLD2	0.1954	14.26
		585.9
Gross Load Growth		30.9
Sub-Total		616.8
Four Percent Cold Snap Factor		24.7
Sub-Total		641.5
Baseload		65.1
Commonwealth Gas Company		5.0
Total 1986-87 Design Day		711.6 MDth

Notes

a. Totals may not add due to rounding.

Source: Exh. EFSC-27

TABLE 4

Boston Gas Company
Summary of Pipeline Supply Contracts and Storage Services

Contract		Type	ACQ (MDth/Yr)	MDQ (MDth/Dy)	Contract Term
Algonquin	F-1	Supply	34,306	127.1	4/72 - 11/96
	F-2	Supply	7,809	21.4	11/86 - 10/09
	F-3	Supply	2,312	6.3	11/86 - 10/09
	WS-1	Supply	2,748	48.2	4/72 - 11/87
	WS-1	Supply	146	---[a]	4/72 - 11/89
	ST-B	Sto/Trans	3,500	29.7	4/80 - 4/00
	SS-III	Sto/Trans	1,064	10.3	4/86 - 3/06
Tennessee	CD-6	Supply	24,403	96.4	3/81 - 11/00
	NOREX[b]	Supply	10,000	43.6	11/89 - ---
	FSST-NE	Transport	---	13.0	12/85 - 3/95
Honeoye		Storage	960	8.0	10/85 - 3/95
Consolididated		Storage	103	0.9	4/81 - 4/00
Penn-York		Storage	877	8.0	4/81 - 3/95
Boundary/INGS		Supply	3,914	10.7	11/87 - ---
Alberta Northeast[b]		Supply	6,388	17.5	11/90 - ---

Notes

a. The MDQ for the 146 MDth of the WS-1 contract that extends until 11/89 is included within the 48.2 MDth/day MDQ for the remainder of the WS-1 contract.

b. Boston Gas has signed precedent agreements with Tennessee for NOREX and with Alberta Northeast.

Sources: Exh. BGC-2, Sec. One, pp. 22-33, and Tables G-22, G-23, and G-24; Exh. EFSC-110.

TABLE 5

Boston Gas Company
Summary of LNG Operating Characteristics[a]

Storage Facility	Storage Capacity (MMCF)	Vaporization Units	Vaporization Capability (MMCFD)	Vaporization Standby (MMCFD)	Liquefaction Capability (MMCFD)	Trucking Capacity (per Day)
Salem	1000	2	15	15	None	12-15
Dorchester	2140	3	125	62.5	6.0	25-30
Lynn	1000	3	57.6	28.8	7.35	25-30
Algonquin	400	None	None	None	None	---[b]
DOMAC	643	6	None	66.6[c]	None	37
Leominster	None	None	2.4	None	None	---[d]
Webster	None	None	2.4	None	None	---[d]

Notes

a. This Table assumes that 1 MMCF is equivalent to 1 MDth.

b. Boston Gas is entitled to use 21.2 percent per day of Algonquin's delivery and receipt facilities.

c. The Company retains rights for 66.6 MMCFD of firm vaporization capacity at DOMAC's Everett LNG facility which Boston Gas believes will be available for the 1986-87 heating season only. The Company, however, has designated such rights as standby capacity available for backing up other firm capacity. The Company has also indicated that an additional 45.0 MMCFD of DOMAC vaporization may be available on a best efforts basis during the 1986-87 heating season.

d. Boston Gas has mobile LNG facilities for transporting LNG to Leominster and Webster and vaporizing directly into the distribution system.

Sources: Exh. BGC-2, Sec. One, pp. 27-33, and Appendix A, Response to Condition Five; Exh. EFSC-7.

TABLE 6

Boston Gas Company
Summary of Recent Liquefaction Activity[a]

	Commercial Point	Lynn
(1) 1986-87 design year liquefaction requirements	1476 MMCF	1573 MMCF
(2) Claimed capabilities	6.0 MMCFD	7.35 MMCFD
(3) Days required to refill 1986-87 design requirements at claimed capability	246 Days	214 Days
(4) Average actual liquefaction rate for all days (percent of capability)	3.91 MMCFD (65%)	3.94 MMCFD (54%)
(5) Days required to refill 1986-87 design requirements at the average actual liquefaction rate	378 Days	400 Days
(6) Number of possible liquefaction days included in sample[b]	274 Days	173 Days
(7) Days in which equipment failure or other problems prevented liquefaction	68 Days	64 Days
(8) Failure rate[c]	25%	37%
(9) Average actual liquefaction rate not including failure days (percent of cap.)	5.20 MMCFD (87%)	6.25 MMCFD (85%)
(10) Days required to refill 1986-87 design requirements at the average actual liquefaction rate without failure days	284 Days	252 Days

Notes

a. Boston Gas liquefied at Commercial Point during the periods April 1, 1986 through January 9, 1987 and April 10 - 30, 1987. At Lynn, the Company liquefied from May 13, 1986 through November 1, 1986.

b. Number of days in Exhs. EFSC-40 and EFSC-113 in which liquefaction equipment was "on" for the season and the LNG tanks were not full.

c. Row 7 divided by row 6.

Sources: Exhs. EFSC-40, EFSC-113, and BGC-2, Table G-22D-LNG.

TABLE 7

Boston Gas Company
Base Case Design Day Supply Plan
(MDth)

	1986-87	1987-88	1988-89	1989-90	1990-91
FIRM REQUIREMENTS:[a]	711.5	723.0	728.6	742.4	753.1
BASE RESOURCES:					
TGP CD-6	96.4	96.4	96.4	96.4	96.4
TGP NOREX	0.0	0.0	0.0	43.6	43.6
TGP FSST-NE	13.0	13.0	13.0	13.0	13.0
Boundary/INGS	0.0	10.7	10.7	10.7	10.7
Alberta Northeast	0.0	0.0	0.0	0.0	17.5
AGT F-1	127.1	127.1	127.1	127.1	127.1
AGT F-2	20.9	20.9	20.9	20.9	20.9
AGT F-3	6.2	6.2	6.2	6.2	6.2
AGT WS-1/SS-III	48.2	48.2	48.2	48.2	48.2
AGT ST-B	29.7	29.7	29.7	29.7	29.7
LNG Commercial Point[b]	187.5	125.0	125.0	125.0	125.0
LNG Commercial Point - New	0.0	62.5	62.5	62.5	62.5
LNG Lynn	57.6	57.6	57.6	57.6	57.6
LNG Salem	15.0	15.0	15.0	15.0	15.0
LNG Leominster/Webster	4.8	4.8	4.8	4.8	4.8
LNG Other (New)	0.0	0.0	40.0	40.0	40.0
Firm Propane	112.9	112.9	112.9	112.9	112.9
TOTAL BASE RESOURCES:	719.2	729.9	769.9	813.6	831.1
SURPLUS (DEFICIT):	7.7	6.9	41.3	71.2	78.0
PRODUCTION RESERVE:					
LNG Lynn	28.8	28.8	28.8	28.8	28.8
LNG Salem	15.0	15.0	15.0	15.0	15.0
Firm Propane Everett	40.0	40.0	40.0	40.0	40.0
TOTAL PRODUCTION RESERVE:	83.8	83.8	83.8	83.8	83.8
TOTAL SUPPLY:	803.0	813.7	853.7	897.4	914.9
SURPLUS (DEFICIT):	91.5	90.7	125.1	155.0	161.8
RESERVE:	12.9%	12.5%	17.2%	20.9%	21.5%

Notes

a. Firm requirements are based on the Company's 1986 forecast filing. The Siting Council found in Section II.E, supra, that the Company's design day forecasting methodology is not appropriate and the resulting forecast of design day requirements is not reliable.

b. For the 1986-87 heating season, 62.5 MMCFD of Commercial Point vaporization is backed up by 66.6 MMCFD of DOMAC vaporization.

TABLE 8

Boston Gas Company
Design Day Contingency Analysis
(MDth)

1. DOMAC Vaporization Not Available

Year	Supply Surplus (Deficit)	Delay of 40 MMCFD Vapor and ANE	DOMAC Contingency	Contingency Surplus (Deficit)	Reserve
1986-87	91.5	0	(62.5)[a]	29.0	4.1%

2. Delay of New Commercial Point Vaporizer for One Year

Year	Supply Surplus (Deficit)	Delay of 40 MMCFD Vapor and ANE	Commercil Pt Vaporizer Contingency	Contingency Surplus (Deficit)	Reserve
1987-88	90.7	0	(62.5)	28.2	3.9%

3. Delay of NOREX

Year	Supply Surplus (Deficit)	Delay of 40 MMCFD Vapor and ANE	NOREX Contingency	Contingency Surplus (Deficit)	Reserve
1987-88	90.7	0	0	90.7	12.5%
1988-89	125.1	(40.0)	0	85.1	11.7%
1989-90	155.0	(40.0)	(43.6)	71.4	9.6%
1990-91	161.8	(57.5)	(43.6)	60.7	8.1%

4. Everett Propane Plant Unavailable

Year	Supply Surplus (Deficit)	Delay of 40 MMCFD Vapor and ANE	Everett Contingency	Contingency Surplus (Deficit)	Reserve
1987-88	90.7	0	(80.0)	10.7	1.5%
1988-89	125.1	(40.0)	(80.0)	5.1	0.7%
1989-90	155.0	(40.0)	(80.0)	35.0	4.7%
1990-91	161.8	(57.5)	(80.0)	24.3	3.2%

Notes: a. Loss of the 66.6 MMCFD DOMAC vaporization rights would result in the designation of a 62.5 MMCFD Commercial Point vaporizer as standby.

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 service of the decision, order or ruling of the Siting Council or within such further time as the Siting Council may allow upon request filed prior to the expiration of 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. (Sec. 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 First Supplement to the Third Long-Range Forecast of Gas Resources and Requirements	)	EFSC 86-13

FINAL DECISION

Robert D. Shapiro
Hearing Officer
November 12, 1987

On the Decision:

Calvin Young
Sheri L. Bittenbender

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The Energy Facilities Siting Council hereby APPROVES the sendout forecast and supply plan filed by Bay State Gas Company for the five years from 1986-87 through 1990-91.

I. INTRODUCTION

A. Background

Bay State Gas Company ("Bay State" or "the Company"), the Commonwealth's third largest local gas distribution company ("LDC"), serves 56 communities in three divisions.[1] In split-year 1985-86[2], the Company had 206,110 on-system firm service customers consisting of 136,417 residential heating customers, 51,878 residential non-heating customers, 17,050 commercial customers, and 765 industrial customers (Exh. HO-2, Tables G-1, G-2, G-3(A) and G-3(B)). Bay State also made firm sales to 16 off-system customers (Exh. HO-3)[3], and sold gas to 71 interruptible customers (Exh. HO-31).

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

Bay State's forecast of sendout by customer class for the heating and non-heating seasons is summarized in Table 1.[4] The Company projects an increase of total normalized firm sendout from 34,919 BBtu in 1986-87 to 38,164 BBtu in 1990-91, representing an annual compound growth rate of 2.25 percent (Exh. HO-2, Table G-5).

1/ Bay State's three divisions are Brockton (serving 39 municipalities), Lawrence (serving 4 municipalities), and Springfield (serving 13 municipalities) (Exh. HO-36).

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

3/ There are two classes of off-system customers: 1) sales for resale (wholesale) to Massachusetts LDC's; and 2) sales for resale to out-of-state LDC's.

4/ 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.

Bay State receives pipeline supplies and underground storage return[5] from the Tennessee Gas Pipeline Company ("Tennessee") at its Agawam, Northampton, East Longmeadow and Lawrence gate stations for redelivery to Bay State's Lawrence and Springfield divisions (Exh. HO-1, pp. 15-16).[6] Bay State receives pipeline supplies and underground storage return from Algonquin Gas Pipeline Company ("Algonquin") through take stations located in Brockton, Canton, South Attleboro, Taunton, and West Medway for redelivery to its Brockton division. Bay State has auxiliary liquefied natural gas ("LNG") facilities in Lawrence and Providence, R.I., and auxiliary propane facilities in Brockton, East Longmeadow, Lawrence, Northampton, Taunton, West Springfield and West Medway (id., Table G-14). Additionally, Bay State leases LNG storage and vaporization facilities from Providence Gas Company ("Providence Gas") (Exh. HO-1, p. 41) and Industrial National Leasing Company ("INLC") (id., Table G-24).

In its last decision involving Bay State, the Energy Facilities Siting Council ("Siting Council" or "EFSC") approved the sendout forecast and supply plan subject to nine conditions. The Company's response to these conditions are outlined and discussed in Sections II.C through II.E and III.C through III.E, infra.

B. History of the Proceedings

On October 15, 1986, the Company filed its sendout forecast and supply plan (Exh. HO-1). On October 29, 1986, 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 provided notice

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

6/ Bay State's Tennessee volumes are delivered to Granite State Gas Transmission, Inc. ("Granite State"), a wholly-owned subsidiary of Bay State, who, in turn, delivers the volumes to Bay State. All of Bay State's contracts with Tennessee for pipeline gas and underground storage return were assigned to Granite State on April 1, 1982.

of the proceeding in accordance with the directions of the Hearing Officer.

Evidentiary hearings were held on April 28 and May 1, 1987. The Company presented three witnesses at the hearing: Charles Ellis, senior vice president, who testified regarding the Company's supply planning process; Christopher G. Gulick, supervisor of gas supply and demand analysis, who testified regarding the Company's sendout forecast and supply plan; and Roberta A. Orris, senior energy supply analyst, who testified regarding the Company's supply plan. The Hearing Officer entered 47 exhibits in the record, largely composed of Bay State's responses to information and record requests. The Company also introduced three exhibits in the record.

Pursuant to a request of the Hearing Officer, the Company submitted a memorandum of law on May 15, 1987.

On September 10, 1987, the Hearing Officer presented a Tentative Decision to the Siting Council. After consideration, the Siting Council voted to reopen the record in the proceeding.

Pursuant to the Siting Council's directive, an evidentiary hearing was held on October 7, 1987. The Company presented supplemental testimony and introduced five additional exhibits in the record.

II. ANALYSIS OF 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. Berkshire Gas Company, EFSC 86-29, p. 2 (1987); Boston Gas Company, EFSC 84-25, pp. 19-20 (1986).

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 forecasting methodology; (b) appropriate, that is, technically suitable for 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. Berkshire Gas Company, EFSC 86-29, pp. 2-3 (1987); Bay State Gas Company, 14 DOMSC 143, 150 (1986); Boston Gas Company, EFSC 84-25, p. 8 (1986).

B. Previous Sendout Forecast Conditions

In Bay State Gas Company, 14 DOMSC 143 (1986), the Siting Council approved Bay State's sendout forecast subject to the following four sendout forecast conditions:[7]

2. That Bay State shall conduct a survey of other local gas distribution companies (at least five) which employ distributive lag econometric models to forecast sendout requirements. The Company shall evaluate the methodological and data issues involved in distributive lag models. Upon completion of the evaluation, a report should be prepared for the Siting Council which summarizes the results and either confirms the appropriateness and reliability of the current forecast methodology or modification of the present methodology. The report should include the results of the study.

3. That Bay State collect and maintain data on gross customer additions and gross customer losses on a monthly basis for each class and division. Also, the Company shall outline how it intends to develop and utilize a historical record on gross customer additions and gross customer losses. Furthermore, the Company shall outline a method for estimating gas usage for new and existing customers. In complying with this Condition, the Company should specifically address the concerns stated in section III.A.l.a.

7/ The numbers preceding each condition correspond to the numbers assigned in the 1986 decision.

4. That Bay State present an analysis of commercial and industrial usage by SIC code. The Company shall address the issue concerning customer usage differences between existing and new customers. Also, the analysis should include a detailed discussion explaining what factors are likely to influence the Company's ability to market gas in the coming five years, including but not limited to: available equipment; technological changes in equipment; cogeneration; demographics; conservation; marketing programs and policy; and gas and oil prices.

5. That Bay State outline the status of off-system contract negotiations with each of its 16 off-system customers. The outline should include, but not be limited to, the firm and optional volumes expected for each off-system customer and the termination date on each existing contract or proposed ending date of renegotiated contracts.

In addition, as Condition Nine of its previous decision, the Siting Council ordered Bay State to comply with the Siting Council's Order in Evaluation of Standards and Procedures for Reviewing Sendout Forecasts and Supply Plans of Natural Gas Utilities, EFSC 85-64, 14 DOMSC 95 (1986)[8] and that Order's implementation in Administrative Bulletin 86-1. Bay State Gas Company, 14 DOMSC 143, 184-186 (1986).

Bay State's compliance with these conditions is discussed in Sections II.C through II.E, infra.

C. Normal Year

1. Description

Bay State uses an econometric model to forecast normal year sendout based on weather data and other explanatory variables. For each division, Bay State defines a "normal year" as the average of twenty

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8/ In its Order in EFSC 85-64, the Siting Council established procedures which render its review of the 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, minimal-environmental-impact supply planning.

years' monthly effective degree days ("EDD") (Tr. I, p. 40).[9] In this case, the Company used the twenty-year period from 1966 to 1985 (Exh. HO-1, Tables DD). The resulting normal year standards are 6,943 EDD for Brockton, 7,276 EDD for Lawrence, and 6,842 EDD for Springfield (id.). The EDD data for Brockton are averages of data taken from Bedford, Massachusetts and Providence, Rhode Island (Tr. II, p. 91). Lawrence's data are drawn from Bedford, Massachusetts and Portsmouth, New Hampshire, while Springfield's data are taken at Bradley Field in Windsor Locks, Connecticut (id.).

The Company uses linear equations based on 16 years of data to project sendout (Exh. HO-1). The Company asserts that it performed Cochrane-Orcutt transformations on its regression equations whenever serial correlation was indicated by the test statistics (Exh. BSG-2; Tr. I, p. 12). The Company further asserts that it used add factoring to adjust some of the Company's equations for actual experience (Exh. HO-1, p. 19; Exh. HO-35; Tr. I, p. 17).

The Company uses the regression equations for the following purposes: (a) to forecast use per meter in each residential class; (b) to forecast the number of meters in each residential class; and (c) to forecast sendout for commercial and industrial classes (Exh. HO-1, Tables 3, 4, 5, 9, 10, 11). The forecasts are derived by applying the appropriate regression equation to estimated values of the explanatory variables.

a. Residential Classes

Bay State uses separate regression equations for heating and general residential customer classes. For each of these classes, Bay State forecasts use per meter and the number of meters. The product of these forecasts is the sendout forecast for each respective residential class (Exh. HO-1, pp. 20-24).

9/ Effective degree days measures the combined effects of temperature and wind (Exh. HO-45). The Company purchases its weather data from Weather Services Corporation (Tr. I, p. 34).

For residential general customers, Bay State estimates use per meter as a function of average gas price, crude oil import price, time, and main extension[10] (id., p. 23). For residential heating customers, Bay State estimates use per meter as a function of EDD, average gas price, time, and post-1978 non-price conservation[11] (id., p. 24). Average gas price and crude oil import price are estimated using a simulation model based on historical price trends (Tr. II, pp. 98-99).

Bay State asserts that a change in the number of residential heating meters is based upon two factors: (1) conversion of residential general customers to gas heating; and (2) "new construction and/or conversions to gas heating by non-customers" (Exh. HO-1, p. 20). For a given split-year, Bay State projects the number of residential heating meters by adding the previous year's meters, the estimated number of conversions, and the estimated number of new meters. The Company states that the number of new residential heating meters is estimated as a function of average gas price, oil price, time, main extension, the number of households in the service territory, the prime rate, and post-1978 conservation (id., p. 26).

The Company states that the number of residential general meters is estimated as a function of average gas price, oil price, time, and post-1978 conservation (id., p. 25).

As shown in Table 1, the Company's Brockton division served 82,432 residential customers in 1985-86 with a total sendout of 7,852 BBtu. Over the forecast period, Bay State projects a 3.0 percent compound annual increase in sendout for the Brockton residential heating class and a 5.3 percent compound annual decrease for the residential general class. For the Lawrence division, which served 34,247 residential customers in 1985-86 with a total sendout of 3,710 BBtu, Bay State

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10/ This is a binary variable which accounts for the existence of main extension policies (Exh. HO-1, pp. 18-19).

11/ The Company asserts that non-price conservation measures such as appliance substitution and insulation of older homes were stimulated by increased energy awareness arising from the enactment of the National Gas Policy Act of 1978 and the second oil price shock in 1978 (Exh. HO-1, p. 24).

projects a 5.1 percent compound annual increase in sendout for both the residential heating and general classes. The Company's Springfield division served 71,616 residential customers in 1985-86 with a total sendout of 6,345 BBtu. Bay State projects a 1.9 percent compound annual increase in sendout for the residential heating class and a 16.4 percent compound decrease in sendout for the residential general class (Exh. HO-2, Tables G-1, G-2).

b. Commercial Classes

For each division, Bay State projects sendout for the commercial heating and commercial general classes by using separate regression equations (Exh. HO-1, pp. 31-39). For both of these classes, Bay State estimates sendout as a function of average gas price, crude oil import price, pipeline curtailment policy, main extension, the number of employees in the SIC group most representative of that division and class, post-1978 conservation, time, and EDD (id.). The Company asserts that Lawrence's commercial heating sendout forecast was additionally a function of rate of return requirements (id., p. 34).

For the Brockton division, which served 7,940 commercial customers in 1985-86 with a total sendout of 4,387 BBtu, Bay State projects a 2.4 percent compound annual increase in commercial sendout for the forecast period (see Table 1). The Company's Lawrence division served 2,586 commercial customers in 1985-86 with a total sendout of 1,517 BBtu. Bay State projects a 3.0 percent compound annual increase in Lawrence's commercial sendout. For the Springfield division, which served 6,524 commercial customers in 1985-86 with a total sendout of 3,720 BBtu, Bay State projects a 1.6 percent compound annual increase in commercial sendout (Exh. HO-2, Table G-3(A)).

c. Industrial Classes

For each division, Bay State projects sendout for the industrial heating and the industrial general classes by using separate regression equations (Exh. HO-1, pp. 31-39). For both of these classes, the Company estimates sendout as a function of average gas price, crude oil import price, the number of employees in the SIC group most representative of that division and class, and post-1978 non-price conservation (id.). For estimating industrial heating sendout, the Company also uses EDD as an independent variable. Further, for Springfield's industrial general class sendout, the Company uses the previous year's average industrial general sales as an independent variable (id., p. 36). Average gas price and crude oil import price are estimated based upon historical trends (Tr. II, pp. 98-99).

The Company's Brockton division served 368 industrial customers in 1985-86 with a total sendout of 1,127 BBtu (see Table 1). Over the forecast period, Bay State projects a 3.2 percent compound annual increase in sendout for the industrial class. For the Lawrence division, which served 175 industrial customers in 1985-86 with a total sendout of 921 BBtu, Bay State projects a 0.3 percent compound annual increase in sendout. The Company's Springfield division served 222 industrial customers in 1985-86 with a total sendout of 1,035 BBtu. Bay State projects a 9.4 percent compound annual increase in Springfield's industrial sendout (Exh. HO-2, Table G-3(B)).

d. Company-Use and Unaccounted-For Gas

For each division, the Company states that Company-use and unaccounted-for gas ("UFG") is forecasted by multiplying estimated sendout for the six customer classes by a factor representing the historical ratio between sales and sendout (Tr. I, pp. 24-25).

Company-use and UFG for split-year 1985-86 totalled 1,627 BBtu (Exh. HO-2, Table G-4(C)). Bay State projects that such sendout will increase 2.8 percent annually over the forecast period.

e. Off-System Sales

Bay State has 16 off-system customers, customers to whom Bay State sells gas for resale. The actual off-system sendout for 1985-86 totalled 2,369 BBtu (Exh. HO-3). Bay State projects off-system sales to decline slightly over the forecast period (Exh. HO-2, Table G-4(B)).

Bay State also provides liquefaction services to its off-system customers (id., p. 44). The Company liquefied 836 BBtu of pipeline gas for five off-system customers during the 1985-86 split-year (Exh. HO-3).

f. Interruptible Sales

Bay State served 71 interruptible customers in 1985-86 (Exh. HO-31). The Company projects that interruptible sales will increase from 16,328 BBtu in 1986-87 to 25,326 in 1990-91 (Exh. HO-2, Table G-4(A)). This represents a compound increase of 11.6 percent per annum. The Company's witness, Mr. Gulick, stated that interruptible sales represent "the total potential interruptible sales that [the Company] think[s] are available" (Tr. II, p. 70). The Company, however, did not provide a study or analysis supporting such an increase in interruptible sales (Tr. II, pp. 69-71).

2. Analysis

a. Compliance with Previous Sendout Forecast Conditions

i. Condition Two

In Condition Two of its last decision, the Siting Council ordered Bay State to conduct a survey of at least five LDC's use of distributive lag models and to provide a report which both summarizes and analyzes the survey's results. Bay State Gas Company, 14 DOMSC 143, 186 (1986). In response, the Company stated that it conducted a telephone survey of seven LDC's and found that only two of those LDC's, Pacific Gas and Electric Company and San Diego Gas and Electric Company, use distributive lag models (Exh. HO-1, pp. 5-6). Further, the Company reported that none of the surveyed companies were able to identify any other companies that used distributive lag models (Exh. BSG-5, p. 2).

Bay State, however, through its conversations with these companies, received sufficient information to evaluate the methodological and data issues involved with distributive lag models. The Company concluded that (1) the distributive lag methodology would be more effective with a database larger than that of Bay State, and (2) the distributive lag methodology lacked a consistent "theoretical justification for the methods used to develop the number of lags and the lag structures" (Exh. BSG-5, p. 2-3).

At the same time, changes in the Company's forecasting methodology have allayed some of the concerns which led the Siting Council to impose Condition Two. The condition was intended to direct the Company to collect information about one technique for correcting the serial correlation which existed in its model due to conservation and other time-dependent factors. Bay State Gas Company, 14 DOMSC 143, 152-153 (1986). In the instant forecast, the Company has used Cochrane-Orcutt transformations to correct its regression equations for serial correlation (Tr. I, p. 12, Exh. BSG-2). In addition, the Company introduced variables for time trend and the impact of the oil price shock of 1978 -- both of which partially capture time-dependent effects of conservation, price, and income on sendout requirements. As a result of these changes, a further investigation of distributive lag models is no longer critical.

Accordingly, the Siting Council finds that Bay State has complied with Condition Two.

ii. Condition Three

In Condition Three of its last decision, the Siting Council required Bay State (1) to collect and maintain data on gross historical customer additions and gross customer losses on a monthly basis, (2) to outline how it intended to develop and utilize a historical record on gross customer additions and losses, and (3) to outline a methodology for estimating gas usage for new and existing customers. The Company was also directed to address specifically the applicability of these data in terms of improving the accuracy of the forecast, and enabling quantitative -- rather than strictly qualitative -- assessment of any reduction in sendout which could be attained with a curtailment policy. Bay State Gas Company, 14 DOMSC 143, 153-54, 186-87 (1986).

In response to the first part of this condition, the Company stated that it collects and maintains data from which monthly gross customer additions and losses could be constructed (Exh. HO-1, pp. 6-7).

In response to the second part of this condition, the Company submitted an analysis comparing actual customer numbers with its fitted estimate of the net number of customers to demonstrate that the net number of customers is an appropriate and adequate variable for forecasting sendout and to show that further disaggregation would be unnecessary (id., p. 7, Appendix A). The Company also stated that it does not possess sales data for gross customer additions and losses, and that, in light of its first argument, obtaining such data would require unnecessary effort (id., p. 7).

In response to the third part of Condition Three, the Company submitted an analysis designed to show that use per customer has not changed over time (id., p. 8, Appendix B). While this analysis addressed historical consumption, it did not consider identifiable trends for future consumption, such as appliance efficiency standards. Still, for purposes of this review, the Siting Council finds that Bay State has adequately addressed the concerns in the third part of Condition Three.

Based on the foregoing, the Siting Council finds that the Company has addressed those parts of Condition Three regarding the applicability of gross customer additions and losses and the usage rates of new and existing customers to its forecasting methodology. In addition, the Company has demonstrated that the reduction in sendout which could be obtained with a curtailment program for the purposes of contingency planning was not highly significant. Accordingly, the Siting Council finds that Bay State has fully complied with Condition Three.

iii. Condition Four

In Condition Four of the last decision, the Company was required (1) to present an analysis of commercial and industrial usage by SIC code, (2) to address the difference in usage between existing and new commercial and industrial customers, and (3) to discuss factors that are likely to influence its ability to market gas to commercial and industrial customers in the next five years. Bay State Gas Company, 14 DOMSC 143, 186 (1986).

In response to the first part of Condition Four, the Company provided tables which rank the annual sendout and percentage of total sendout of SIC-coded commercial and industrial customers for 1984, 1985 and 1986 (Exh. HO-1, pp. 9-13, Tables 1 and 2). While these tables do not constitute an analysis, as required by the Siting Council's last decision, the Company's response to the second part of Condition Four, below, has eliminated the need to present any such analysis.

In its response to the second part of Condition Four, the Company provided the Siting Council with an analysis designed to show that usage has not significantly changed over time. The Company studied general-class commercial customers in its Springfield division since the Company had determined that this subgroup of customers had demonstrated the greatest fluctuation in usage over time (Exh. HO-1, p. 12, Appendix C). The Siting Council finds that the results of Bay State's study of Springfield commercial customers demonstrates that further disaggregation of usage would not significantly increase the reliability of the Company's forecast. Further, in light of the changing composition of the Company's commercial and industrial sales evidenced in the Company's response to the first part of Condition Four, the Company's analysis indicates that the composition of commercial and industrial customers does not have a significant impact upon use per customer.

In response to the third part of Condition Four, the Company addressed those factors which affect the Company's ability to market gas to commercial and industrial customers (Tr. I, pp. 25-32).

Accordingly, the Siting Council finds that the Company has fully complied with Condition Four.

iv. Condition Five

In Condition Five of the last decision, the Company was required to report on the status of negotiations with off-system customers. Bay State Gas Company, 14 DOMSC 143, 187 (1986). In response, the Company submitted a report on the status of these negotiations and their impact upon sendout requirements (Exh. HO-1, pp. 13-14; Exh. HO-4; Tr. I, pp.

41-47). Accordingly, the Siting Council finds that Bay State has complied with Condition Five as set forth in the most recent Siting Council order.

v. Condition Nine

As part of Condition Nine of the last decision, the Siting Council ordered Bay State to describe its approach to normalization for weather and report on the accuracy of its past forecasts. Bay State Gas Company, 14 DOMSC 143, 184, 187 (1986). Bay State has provided documentation that demonstrates that it incorporates weather into its forecast of sendout requirements by including EDD as an explanatory variable when it estimates sendout for its heating use customer classes in each division (Exh. HO-1, pp. 24, 31-36). Accordingly, the Siting Council finds that Bay State has complied with that portion of Condition Nine pertaining to its normalization method.

Bay State also filed Table FA which compares the Company's past forecasts with the actual normalized sendout for those years (Exh. HO-1, Table FA). Accordingly, the Siting Council finds that Bay State has complied with that portion of Condition Nine pertaining to forecast accuracy.

b. Forecasting Methodology

In that Bay State has provided sufficient documentation in its filing and its responses to information requests, the Siting Council finds that Bay State's normal year forecasting methodology is reviewable. The Siting Council also finds that the general structure of the Company's econometric forecasting methodology is appropriate for a company of Bay State's size and resources. Finally, the Siting Council finds that the Company's normal year standards, calculated as the average of the twenty most recent years of EDD data, ensure a reliable forecast.

However, the Company's normal year forecast raises certain issues regarding the Company's methodology, data, and assumptions.

First, the small size of Bay State's database raises two problems in the immediate forecast. In some cases, data limitations required the

Company to make judgmental determinations eliminating certain explanatory variables from its equations that Bay State might otherwise have wanted to use (Tr. I, p. 15). Moreover, as a general concern, databases as small as Bay State's (i.e., only 16 data points (Exh. HO-1, p. 18)) result in less efficient, and hence less reliable, predictions than those based on a larger database.

In addition, the Company's witness, Mr. Gulick, testified that the Company had discontinued its use of log-linear equations, the form used in its last forecast, because of certain assumptions implicit in that structure (Tr. I, pp. 15-16). However, Mr. Gulick also testified that no other structural specifications had been considered (id., p. 11). Instead, the Company made judgmental adjustments to certain independent variables (Tr. I, p. 17). The Company's decision to make judgmental adjustments to explanatory variables without systematically examining the structural form of the equation itself raises questions about the reliability of the forecast.

Notwithstanding these concerns, the Siting Council finds that Bay State's forecast is based upon adequate econometric reasoning and methods, and a satisfactory disaggregation into service classes and divisions. Accordingly, the Siting Council finds that the normal-year forecast methodology is reliable.

D. Design Year

1. Description

To forecast sendout in a design year, the Company employs the equations developed to forecast normal year sendout, but bases the predictions on design year EDD.

Bay State plans for a design year based upon different EDD for each of its three divisions: 7,637 EDD in Brockton, 8,004 EDD in

Lawrence, and 7,526 EDD in Springfield (Exh. HO-1, Tables DD). The Company's design heating season standard is obtained by adding ten percent of a normal year's EDD to a normal winter's EDD for each division (Exh. HO-6; Tr. II, p. 103). The Company's design non-heating season is the same as its normal heating season (Exh. HO-1, Tables DD).

In support of the reliability of the respective divisional EDD standards, the Company provided a recurrence expectancy calculated from a different database (i.e., Logan-Bedford) than those which the Company uses in its divisions. Bay State argued that this recurrence expectancy is the same as that which would have been calculated using any of the divisional databases. In calculating this recurrence expectancy, the Company (1) computed a normal year's degree days ("DD"), (2) computed a normal winter's DD for Logan-Bedford DD data collected from 1934 to 1965, (3) added 10 percent of the normal year's DD to the normal winter's DD, and (4) calculated that such a winter would have a probability of recurrence of 1 in 68 (Exh. BSG-5, Attachment 3). In regard to the reliabilty of the particular divisional EDD standards, the Company states that (1) in using such standards (i.e., standards calculated using the methodology described above), the Company has always been able to meet the sendout requirements of its customers, and (2) the design year is a "judgment call" based on 30 years' experience (Tr. III, pp. 75-76).

2. Analysis

Since the Siting Council has already found that the Company's normal year method is reviewable and appropriate, the Siting Council also finds that the design year forecasting methodology is reviewable and appropriate. To determine whether the design year forecast is reliable, the Siting Council examines the design year EDD standards to which the methodology is applied.

In its last decision, as part of Condition Nine, the Siting Council ordered Bay State to provide a rationale for the selection of its design year standard. Bay State Gas Company, 14 DOMSC 143, 184, 187 (1986). In response to this condition, the Company provided the Siting Council with minimally acceptable information explaining the derivation of this standard. Accordingly, the Siting Council finds that the Company has complied with that part of Condition Nine pertaining to its design year standard.

The Company's response to Condition Nine, however, has raised new questions regarding the reliability of Bay State's design year standard. In support of its design year standards, Bay State argues: (1) that a recurrence expectancy for Logan-Bedford data of 1 in 68 represents the design year standards for the Company's three divisions; and (2) that the Company's successful track record over a thirty-year period justifies a methodology based on the "judgment calls" of senior management.

In regard to the first contention, the Company's computation of a recurrence expectancy (1) compares Logan-Bedford data to data collected at other locations, (2) uses data from 1934 to 1965 to justify standards based on data collected from 1966 to 1985, and (3) is based on DD data rather than EDD data. Yet Bay State did not address whether temperature data collected at different locations would vary in relative coldness or warmness or in relative variability due to such factors as elevation, geographical location, or proximity to large bodies of water. Because of such influences, temperature data collected at one location may not provide a good basis for analyzing data collected at another. Additionally, because the Company presented no evidence that data from 1934 to 1965 provide a valid basis for analyzing data from 1966 to 1985, there is no reason to conclude that statistics based on the earlier data would be the same as those derived from more current data. Finally, EDD data is based on considerations other than temperature (e.g., wind, snow cover) and, therefore, statistical results arising from DD data may not be immediately applicable to EDD data.

In regard to the second contention, the Company's claim that it has never encountered a supply problem is hardly acceptable from a company of Bay State's size and resources. The Siting Council acknowledges that a track record is arguably an indicator of reliability as it relates to adequacy of supply. Still, a successful track record alone is inherently incapable of revealing instances where a company has overemphasized adequacy in its design year planning standards. In those instances, a company may operate pursuant to standards that are too high and that ultimately result in unacceptable cost implications.

The Company, however, has stated that because additional supplies are purchased only when needed, the added costs of meeting design heating season requirements are incurred only if design conditions arise (Exh. BSG-5, p. 10, Tr. III, p. 76). In this manner, the Company asserted that the costs associated with design year planning are not strictly tied to the particular design year standard used. In order to demonstrate that such a planning process ensures adequate supply, the Company discussed the availability of the supplies it would need under design conditions, and the lead times and transportation arrangements required to obtain these supplies (Tr. III, pp. 78-82). In rejecting this argument, the Siting Council once again notes that the Company's emphasis upon an ability to ensure an adequate supply has unnecessarily obscured its responsiblity to consider tradeoffs between adequacy and cost.

Finally, Bay State appears to have taken steps to address the problems in its design year methodology. Throughout this proceeding, Bay State has indicated that it intends to present a new weather analysis in its next filing which addresses many of these problems (Tr. III, p. 73), and, in fact, has contracted to purchase a new weather data set (Tr. III, p. 19). The Siting Council finds that Bay State's efforts to remedy the problems in its weather analysis, along with its track record of reliability in regard to adequacy of supply, constitute a reliable methodology for the design year. In making this finding, the Siting Council specifically notes the dynamic nature of methodological change and the importance of allowing companies to gradually develop their methods to meet the Siting Council's standards. Therefore, for purposes of this review, the Siting Council finds that Bay State's design year methodology is reliable. However, the Siting Council ORDERS 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.

Accordingly, the Siting Council finds that Bay State's design year forecasting methodology is reviewable, appropriate and reliable.

E. Peak Day

1. Description

Bay State uses a peak day[12] standard of 77 EDD for each of its three divisions (Exh. HO-1, Tables DD). Historically, Bay State used a 67 degree day standard. The Company's witness, Mr. Gulick, stated that Bay State changed its peak day standard after a Weather Services Corporation expert "indicated that an appropriate adjustment to our current design day of 67 would be ten, resulting in a 77 effective degree day" (Tr. I, p. 39).

In support of its peak day standard, the Company provided a document which listed the annual Logan-Bedford peak day degree days collected from 1934 to 1965 and, based on this data, showed that the selected design day standard would have a probability of recurrence of 1 in 33 (Exh. BSG-5, Attachment 1). The Company provided little support for the appropriateness of this standard, noting instead that the peak day standard is a "historical company operating standard" that has been in effect in the gas industry for close to thirty years (Tr. III, p. 51-52). In support of its design day standard, the Company's witness, Mr. Ellis, asserted that Bay State had met design day conditions on a number of occassions over the years (Tr. III, p. 67). Mr. Gulick also testified that the Company has contracted for more comprehensive data which it expects will better represent actual conditions in each territory (Tr. I, p. 39; Tr. III, p. 19).

In support of its peak day forecast, the Company also provided a table which set forth its baseloads and heating increments for each division (Exh. HO-35, p. 8). Peak day sendout for each division is derived by multiplying the heating increments by the appropriate effective degree day standard and summing this product with the baseload.

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

2. Analysis

While the Company has provided minimal documentation in support of its design day forecast methodology, for purposes of this review, the Siting Council accepts that methodology as reviewable and appropriate. To determine whether the design year forecast is reliable, the Siting Council examines the peak day EDD standard to which the methodology is applied.

In its last decision, as part of Condition Nine, the Siting Council ordered Bay State to provide a rationale for the selection of its peak day standard. Bay State Gas Company, 14 DOMSC 143, 184, 187 (1986). In response to this Condition, the Company provided the Siting Council with minimally acceptable information explaining the derivation of this standard. Accordingly, the Siting Council finds that the Company has complied with that part of Condition Nine pertaining to its peak day standard.

The Company's response to Condition Nine, however, has raised new questions regarding the appropriateness and reliability of Bay State's peak day standard. In support of its peak day standard, Bay State (1) addresses the recurrence expectancy of its peak day; and (2) points to a successful track record in operating pursuant to its methodology.

In response to the Company's arguments, the Siting Council notes that Bay State has based its contentions on outdated weather information (data collected between 1934 and 1965) and purely qualitative assessment. Further, Bay State's weather data for each of its three service territories raise serious questions regarding the Company's use of the same peak day standard for all three divisions. In its forecast of normal-year and design-year sendout for each division, the Company assumes the EDD's vary by division. The normal year standard ranges from 6,842 for the Springfield division to 7,276 for the Lawrence division; the design year standard ranges from 7,526 for the Springfield division to 8,004 for the Lawrence division (Exh. HO-1, Tables DD). In the face of such data, however, the Company still applies the same 77 EDD peak day standard to all three divisions. The Company argues that the incremental cost of changing its peak day standard by one degree day is "miniscule" (Tr. III, p. 58), and further asserts that although it expects it will obtain standards that differ by division when it applies its new weather data, these standards will not differ significantly from the current standard (Tr. III, p. 52). In sum, the Company argues that its single peak day standard is adequate to ensure that supply planning decisions made for each division are both cost-effective and reliable.

Finally, Bay State appears to have taken steps to address the problems in its design day methodology. Throughout this proceeding, Bay State has indicated that it intends to present a new weather analysis in its next filing which addresses many of these problems (Tr. III, p. 73), and, in fact, has contracted to purchase a new weather data set (Tr. III, p. 19). The Siting Council finds that Bay State's efforts to remedy the problems in its weather analysis, along with its track record of reliability in regard to adequacy of supply, constitute a reliable methodology for the design day. In making this finding, the Siting Council specifically notes the dynamic nature of methodological change and the importance of allowing companies to gradually develop their methods to meet the Siting Council's standards. Therefore, for purposes of this review, the Siting Council finds that Bay State's peak day methodology is reliable. However, the Siting Council ORDERS 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.

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

F. Summary

In summary, the Siting Council finds that Bay State has complied with Conditions Two, Three, Four, Five and Nine of its last decision.

The Siting Council also finds that the Company's normal year, design year, and peak day sendout forecast methodologies are reviewable,[13] appropriate, and reliable.

Accordingly, the Siting Council hereby APPROVES the Company's forecast of sendout requirements.

13/ In order to determine that Bay State's sendout forecast methodologies were reviewable, the Siting Council was required to make numerous requests, both through discovery and questioning of witnesses to obtain documentation which should have been included in the initial filing. The review process would have been expedited and enhanced had the initial filing been more fully documented. The Siting Council has held that a company's filing must be self-contained and supported by sufficient documentation. Eastern Utilities Associates, 11 DOMSC 61, 65 (1984).

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. Berkshire Gas Company, 14 DOMSC 107, 128 (1986); Holyoke Gas and Electric Light Department, 15 DOMSC 1, 27 (1986); Fitchburg Gas and Electric Light Company, 15 DOMSC 39, 54 (1986); Westfield Gas and Electric Light Department, 15 DOMSC 67, 72 (1986); Fall River Gas Company, 15 DOMSC 97, 111 (1986). 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 require the Siting Council to review adequacy both in terms of a company's base plan and its contingency plan.[13A] Berkshire Gas Company, EFSC 86-29, p. 17 (1987).

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. Id.

13A/ 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, EFSC 84-25, p. 33 (1986); Fitchburg Gas and Electric Light Company, 15 DOMSC 39, 53 (1986); Fall River Gas Company, 15 DOMSC 97, 115 (1986); Berkshire Gas Company, 14 DOMSC 107, 127 (1986); Bay State Gas Company, 14 DOMSC 143, 168 (1986); Essex County Gas Company, 14 DOMSC 189, 201-202 (1986).

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. Id., p. 18.

The Siting Council also reviews the cost of a utility's supply plan in terms of cost minimization, subject to trade-offs with adequacy of supplies. Id.

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. Berkshire Gas Company, 14 DOMSC 107, 128 (1986).

B. Prior Supply Conditions

In Bay State Gas Company, 14 DOMSC 143 (1986), the Siting Council approved Bay State's supply plan subject to the following three conditions:[14]

6. That Bay State discuss in detail its participation in the new supply projects for which applications are pending at FERC or approved by FERC within the twelve month period

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14/ The numbers preceding each condition correspond to the numbers assigned in the 1986 decision.

preceding the Company's new forecast filing. In particular, the Company should at a minimum describe the status of each project, the pipeline system through which the gas will be transmitted, the volumes Bay State proposes to receive directly from each project, and the volumes Granite State proposes to receive from each project.

7. That Bay State provide a detailed description on the status of DOMAC LNG and submit a contingency supply plan for meeting sendout requirements in normal and design years and on a peak day should DOMAC supplies not be available as expected.

8. That Bay State describe the flexibility in its contracts with Granite State to move pipeline and underground storage volumes between Lawrence and Springfield and determine whether cost and reliability reasons exist for treating these two divisions as a single unit for peak day supply planning purposes.

In addition, as Condition Nine of its previous decision, the Siting Council ordered Bay State to comply with its Order in Evaluation of Standards and Procedures for Reviewing Sendout Forecasts and Supply Plans of Natural Gas Utilities, EFSC 85-64, 14 DOMSC 95, 104 (1986) and that Order's implementation in Administrative Bulletin 86-1. Bay State Gas Company, 14 DOMSC 143, 184-186 (1986).

Bay State's compliance with these conditions is discussed in Sections III.C through III.E, *infra*.

C. Resources and Facilities

1. Pipeline Gas and Storage Services

a. Existing Deliveries and Services

Bay State receives deliveries of pipeline gas and storage return gas from Algonquin and Granite State (Exh. HO-1, Table G-24). Algonquin delivers firm gas and provides storage services under rate schedules F-1, F-4, WS-1, STB, and SS3; Granite State's gas comes entirely from Tennessee under a CD-1 rate schedule (*id.*). In addition, Bay State has agreements with Consolidated Gas Supply Corporation and Penn-York Energy

Corporation for underground storage services in New York and Pennsylvania (id.). Storage volumes under these two agreements are returned through Granite State by Tennessee under rate schedules GSS-1 and S-1 (id.). The Company's maximum daily quantities ("MDQ") and annual volumetric limits ("AVL") under each of these contracts are summarized in Table 2.

Algonquin's F-1, F-4, and WS-1 contracts expire during the five-year forecast period (id.). The Company asserts that "there is no question ... that [the contracts] will be renegotiated" (Tr. II, p. 84).

b. Planned Deliveries and Services

As part of Condition Six of its last decision, the Siting Council ordered Bay State to describe its participation in all new gas supply projects that were pending before FERC or recently had been approved by FERC. The Company submitted a detailed discussion of new projects in which it is participating (Exh. HO-1, pp. 14-15). Accordingly, the Siting Council finds that the Company has complied with Condition Six.

The Company states that it plans to begin receiving increased CD-1 supplies from Granite State on November 1, 1987, due to Granite State's participation in Tennessee's Interim Natural Gas Service ("INGS") project (id., p. 40). The Company further states that Tennessee has received FERC approval to provide INGS service which, in turn, will be succeeded by Boundary Phase II volumes (id., p. 15).[15] Granite State's entitlement under Boundary/INGS provides for an MDQ of 2.7 MMcf, of which 2.4 MMcf per day is allocated to Bay State, and an AVL of 980 MMcf (id.).

Bay State also asserts that it plans to begin receiving additional CD-1 volumes from Granite State on November 1, 1987, due to Granite State's intended purchases from Shell Canada Ltd. ("Shell") as part of the Portland Gas Pipeline project. The Portland Gas Pipeline project, as proposed and developed by Granite State, involves conversion of an existing oil pipeline which runs from Montreal, Canada, to Portland, Maine. As of the close of this record, the project had received

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15/ Due to the highly integrated nature of the Boundary and INGS projects, the Siting Council will refer to them as a single supply known as Boundary/INGS or simply Boundary.

certification from FERC but was awaiting a zoning ordinance (Tr. III, pp. 91-92). The Company states that it expects initially to receive 7.9 BBtu per day from Shell on an interruptible basis. Bay State anticipates that it will receive 19.7 BBtu on a firm basis as of November 1, 1988 (id., pp. 40-41).

Finally, the Company states that it plans to begin receiving increased volumes under its Algonquin F-4 rate schedule on November 1, 1987. An increased MDQ of 5.1 BBtu and AVL of 1,865.9 BBtu have already been approved by FERC, and a FERC decision on further supplemental volumes of 0.5 BBtu per day and 211.0 BBtu per year is pending (id., p. 14).

c. Spot Purchases of Pipeline Gas

The Company states that it plans to purchase large quantities of spot market gas to (1) serve expanding interruptible markets such as electric companies and (2) augment firm supplies when appropriate (Exh. HO-1, p. 41). The Company's witness, Mr. Gulick, stated that the amount of spot market gas purchased is not selected as a result of any market studies, but represents the projected difference between firm supplies and projected interruptible sales (Tr. I, p. 51).

2. LNG

Bay State purchases LNG from Distrigas of Massachusetts Corporation ("DOMAC") pursuant to a contract which provides annual volumes of 2,610 BBtu through December 31, 1997 (Exh. HO-1, Table G-24).

In response to that portion of Condition Seven of the last Siting Council decision requiring the Company to report on the status of these DOMAC supplies, the Company stated that DOMAC has not delivered any LNG since September, 1985 (Tr. II, p. 32).[16] Accordingly, the Siting

16/ Because the Company's supply plan includes deliveries of DOMAC LNG, a supply which Bay State has stated that it is not receiving, the Siting Council will treat DOMAC LNG as a contingency in its review of the adequacy of Bay State's supply plan. See Section III.D.2., infra.

Council finds that the Company has minimally complied with that part of Condition Seven pertaining to a status report on DOMAC LNG.

Bay State owns one LNG facility in Lawrence and leases three others from INLC (Exh. HO-1, Tables G-14 and G-24). Together, these facilities have a storage capacity of 1840.8 BBtu and can vaporize a total of 121.2 BBtu per day.

For the 1986-87 heating season, Bay State has contracted for additional peak-day LNG vaporization service from Providence Gas. Providence Gas will vaporize up to 10 BBtu per day. Under the contract, Providence Gas will vaporize a maximum of 30 BBtu of gas during the heating season (Exh. HO-1, p. 41).

3. Propane

Currently, Bay State contracts for short-term and spot propane gas on a year-to-year basis. For the 1986-87 heating season, the Company has made short-term propane purchases from Gas Supply, Inc., Petrolane Gas Service, Inc. and Sea-3, Inc. totalling 1,100.9 BBtu (Exh. HO-5).

The Company also owns seven propane facilities which have a combined storage capacity of 320.2 BBtu and a combined vaporization capacity of 110 BBtu per day.

D. Adequacy of Supply

1. Base Case Analysis

In reviewing Bay State's current supply plan, the Siting Council must determine whether the Company has adequate resources to meet projected sendout requirements under a reasonable range of contingencies. In order to make this determination, the Siting Council examines whether the Company's "base case" resource plan is adequate to (1) meet firm sendout requirements under normal, design, peak day, and cold snap weather conditions, and (2) meet those firm sendout requirements under a reasonable range of supply contingencies. Berkshire Gas Company, EFSC 86-29, p. 22 (1987).

If the Siting Council determines that the Company's "base case" plan is not adequate to meet sendout under a reasonable range of contingencies, the Company must establish that it has an action plan to meet those projected firm sendout requirements. Id.

a. Normal Year/Design Year

In normal and design years, Bay State must have adequate supplies to meet several types of requirements. Above all, Bay State must meet the requirements of its firm on-system customers. In addition, the Company must ensure that its storage facilities are filled prior to the start of the heating season. To the extent possible, Bay State also supplies gas to its interruptible customers.

The Company provided its normal and design year supply plans in Tables G-22N and G-22D of its filing (Exh. HO-1) which are summarized in Tables 3 through 6. These tables indicate that the Company would have adequate supplies to meet its forecasted normal and design year requirements.

Accordingly, the Siting Council finds that Bay State's base case supply plan is adequate on a seasonal basis to meet the Company's forecasted normal year and design year sendout requirements.

b. Peak Day

Bay State must have adequate supply capability to meet the requirements of its firm customers on a peak day. While total supply capability necessary for meeting normal and design year requirements is a function of the aggregate volumes of gas available over some contract period, peak day supply capability is determined by the maximum daily deliveries of firm pipeline gas and the maximum rate at which supplementals may be dispatched.

Bay State's peak day planning for Lawrence and Springfield is limited by its CD-1 contract with Granite State which supplies gas to these two divisions jointly. The combined daily take limitations under this contract (47.0 BBtu for Lawrence and 71.5 BBtu for Springfield (Exh. HO-11)) exceed the joint MDQ of 82.2 BBtu (Exh. HO-1, Table G-24). In order to ensure that this interdependency does not negatively impact the ability of the Company to meet its peak day sendout requirements, the Siting Council, in Condition Eight of its previous decision, ordered BayState to discuss the flexibility of its Granite State contracts and to address whether peak day planning for the two divisions should be considered as one unit.

In response to this condition, the Company provided tables and narratives indicating the maximum daily volumes of CD-1 gas that will be available to each division over the forecast period and detailing the various combinations in which these volumes and the applicable supplemental and underground storage volumes can be utilized to meet peak day sendout requirements in each division and to minimize the use of more expensive peak shaving supplies (Exh. BSG-4, pp. 40-46, Attachments 5-10). The Company notedthat the "actual dispatching treats [these two divisions] as one division balancing the system as needed with supplemental supplies" (Exh. HO-1, p. 17). Accordingly, the Siting Council finds that Bay State has complied with Condition Eight.

The Company presented its peak day supply plan in Table G-23 (Exh. HO-1) which is summarized in Table 7. This table indicates that Bay State would have adequate supplies to meet its forecasted peak day requirements.

Accordingly, the Siting Council finds that Bay State's base case supply plan is adequate to meet its forecasted firm peak day sendout requirements.

c. Cold Snap

In Condition Nine of its last decision, the Siting Council ordered Bay State to provide an analysis of its cold snap preparedness or an explanation of why such an analysis is unnecessary. Bay State Gas Company, 14 DOMSC 143, 186 (1986). The Siting Council has defined a cold snap as a prolonged series of days at or near peak conditions. Id., p. 185. A company must demonstrate that the aggregate resources available to it are adequate to meet the 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.

In response to Condition Nine, Bay State provided an explanation of why an analysis of cold-snap preparedness was unnecessary to demonstrate the Company's ability to meet a cold snap (Exh. HO-9). Therefore, the Siting Council finds that Bay State has complied with that portion of Condition Nine pertaining to cold-snap preparedness.

However, the Company's response raises questions as to whether such an analysis is, in fact, unnecessary. While the Company has adequate capacity and supplies to meet its forecasted peak day and has adequate resources to meet its forecasted design heating requirements throughout the forecast period, the Company's ability to meet a cold snap is dependent upon the prudent management of its propane and LNG supplies as well as its ability to transport necessary supplies to its facilities. The Company has enumerated some of the variables which must be considered during peak conditions in order to insure that adequate propane and LNG supplies are available to meet an extended period of cold days (Exh. HO-9). In light of such a large number of factors, a comprehensive review of the Company's cold-snap preparedness would require a complete analysis of the Company's ability to meet a cold snap under various conditions. The Siting Council therefore rejects the Company's assertion that a cold-snap analysis is unnecessary and ORDERS the Company to submit a cold-snap analysis in its next filing.

2. Contingency Analysis

In determining the adequacy of a company's supply plan, the Siting Council identifies certain key contingencies and evaluates the company's ability to meet forecasted requirements if such contingencies occur. For example, even if certain existing resources become unavailable due to delivery problems or if certain planned new supplies are delayed or cancelled, a company has to demonstrate that it has adequate resources to meet projected firm sendout requirements. If a company cannot establish that it has adequate resources in the event that certain identified resources are not available, it must then demonstrate that it has an action plan to meet sendout requirements in the absence of those resources.

In the case of Bay State, the Siting Council's analysis focuses on the Company's supply preparedness under two contingencies relating to DOMAC LNG and the Portland Gas Pipeline project. First, the Siting Council identifies DOMAC LNG supplies as a planning contingency, since Bay State has not received expected deliveries for some time (Tr. II, p. 32). The Siting Council also identifies the new gas supplies associated with the Portland Gas Pipeline project as a planning contingency because proposed pipeline projects involving licensing and development of facilities are often subject to delay.[17] Therefore, the Siting Council considers the ability of the Company to meet sendout if (1) DOMAC LNG is unavailable, (2) the Portland Gas Pipeline project is delayed, and (3) both DOMAC and the Portland Gas Pipeline volumes are unavailable.

In responding to Condition Seven of the last Siting Council decision, the Company submitted a plan indicating that, in the absence of DOMAC LNG, it could liquefy more pipeline gas and thus would be able to meet all of its normal and design year requirements without an action plan (Exh. HO-1, Appendix D). Further, the Company's existing plan for meeting peak day sendout does not include DOMAC LNG (Exh. HO-1, Table G-23). Accordingly, the Siting Council finds that Bay State has adequate resources to meet forecasted normal year, design year, and peak day sendout requirements throughout the forecast period in the event that DOMAC LNG is unavailable. Further, the Siting Council finds that the Company has complied with Condition Seven of its last decision.

In the event that the firm volumes associated with the Portland Gas Pipeline project were delayed but DOMAC LNG supplies were still available, Bay State would be able to meet its forecasted sendout requirements with its base case supplies throughout the forecast period (Exh. HO-1, Tables G-22N, G-22D, and G-23). Accordingly, the Siting Council finds that Bay State has adequate resources to meet its forecasted normal year, design year, and peak day sendout requirements

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17/ In the past, the Siting Council has treated projects involving the development and licensing of facilities as supply contingencies. Massachusetts Municipal Wholesale Electric Company, EFSC 85-1, pp. 26-28 (1987); Berkshire Gas Company, EFSC 86-29, p. 27 (1987).

throughout the forecast period in the event that the Portland Gas Pipeline project is delayed.

In the event that DOMAC LNG continued to be unavailable and the Portland Gas Pipeline volumes were delayed, the Company's base case supply plan would not be sufficient to meet forecasted design heating season sendout requirements from 1988-89 to 1990-91 (Exh. HO-1, Appendix D). The Company has stated, however, that should the Portland Gas Pipeline project be delayed, Bay State would meet design year sendout requirements by increasing short-term and spot market purchases of propane (Tr. II, pp. 102-103). Accordingly, the Siting Council finds that Bay State has established that it has an action plan for securing the necessary supplies to meet forecasted sendout requirements in the event that the Portland Gas Pipeline project is delayed and DOMAC LNG supplies are unavailable.

3. Conclusions on the Adequacy of Supply

The Siting Council has found that, based on the Company's forecasts as presented, Bay State has adequate resources to meet "base case" sendout requirements in the normal year, design year, and on a peak day. The Siting Council is unable to conclude whether the Company is able to meet its sendout requirements in the event of a cold snap. The Siting Council has also found that if DOMAC LNG volumes are not available, or if the Portland Gas Pipeline project is delayed, the Company has adequate base case supply to meet its forecasted sendout requirements under normal year, design year, and peak day conditions. The Siting Council has also found that the Company has an action plan for securing supplies to meet its forecasted normal year, design year, and peak day sendout requirements throughout the forecast period in the event that the volumes associated with the Portland Gas Pipeline project are delayed and DOMAC LNG is unavailable.

Accordingly, the Siting Council finds that Bay State has adequate resources to meet its normal year, design year, and peak day sendout requirements during the forecast period.

E. Least-Cost Supply

1. Supply Cost Analysis

The Siting Council recently articulated its concerns regarding the need for gas companies to engage in least-cost planning. In its Order in Docket No. 85-64, 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 the 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 needs, since options with similar reliability may have different costs and vice versa, and since different load additions with varying gas usage patterns impose different kinds of supply obligations in terms of cost.

In its most recent decision regarding Bay State, the Company was ordered to comply with the Siting Council's Decision in Docket No. 85-64 and its implementation in Administrative Bulletin 86-1. Specifically, to enable the Siting Council to ensure that the Company's supply plan minimizes cost, the Company was ordered, as part of Condition Nine, 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 addition of a long-term firm gas supply contract. Bay State Gas Company, 14 DOMSC 107, 185-186 (1986).

In the instant case, Bay State's decision to add gas volumes associated with the Boundary/INGS project, the F-4 expansion project, and the Portland Gas Pipeline project triggered the need for such studies. In particular, cost studies were required in order to evaluate whether these new projects were least-cost additions to the Company's existing supply plan, taking adequacy and reliability concerns into account. Bay State provided such studies as well as analyses of the costs associated with conservation and load management ("C&LM") options.

a. Conservation and Load Management

Bay State's C&LM analyses evaluated the costs and benefits of seven conservation programs and three types of load management (Exh. BSG-5, pp. 10-19, Attachments 4-9). Based on these analyses, the Company asserts that these conservation programs are not cost justified (id., p. 16). The Company also asserts that it is implementing those load management measures that are currently practical, such as targeted load additions (id., p. 13), while eschewing impractical measures such as load elimination and load shifting (id., pp. 10-12).

Accordingly, the Siting Council finds that Bay State has adequately considered conservation and load management in its current supply plan.

b. Boundary/INGS and F-4 Expansion

The Company submitted a historical account of the supply options which were available when it was negotiating and committing itself to the Boundary/INGS project (Exh. BSG-4, pp. 7-30). These options included retaining its contract for SNG with Algonquin (id., p. 10), increasing purchases from DOMAC LNG (id., p. 12), expanding Bay State's LP air gas production (id., p. 13), and examining other new pipeline supplies (id., p. 12).

As presented by Bay State, this historical account set forth supply options available at the time and costs associated with them. First, the unit cost of SNG was almost twice that of Boundary volumes, and DOMAC LNG was slightly more expensive than Boundary (id., pp. 10-12). The Company noted that although DOMAC LNG was a reasonably reliable peak shaving gas supply, it was not "a reasonably reliable base load gas supply" (id., p. 12). The Company also noted that LP air gas was far more expensive than Boundary and, further, limited by the availability of natural gas necessary to mix with the LP air gas (id., p. 13). Finally, Bay State stated that, at the time, new pipeline supplies were not available directly from either Tennessee or Algonquin (id., p. 12).

Somewhat later in the negotiation process, the CONTEAL project, with a more favorable price than that of Boundary, was offerred by Algonquin, Consolidated, and Texas Eastern Gas Pipeline Company as an alternative to Boundary (id., p. 14). As the Boundary negotiations proceeded, however, Boundary's estimated delivered price decreased until it was priced competitively with that of the CONTEAL project and was even more favorably priced in comparison to Algonquin SNG, DOMAC LNG, and LP air gas. During this negotiation period the volumes offerred Bay State by Boundary also decreased until Boundary and CONTEAL each offerred Bay State approximately half the total volumes it needed to completely replace Algonquin SNG. Consequently, Bay State stated that it elected to sign with both projects. Subsequently, Bay State entered into F-2, F-3, and F-4 purchase agreements with Algonquin to replace volumes that would be lost when the CONTEAL project expired (id., pp. 18, 22). These replacements were offerred at costs roughly comparable to those of CONTEAL (id., Attachment 4) yet were substantially less expensive than LNG, SNG, or LP air alternatives. The Company also stated that no other new pipeline supplies were available when Bay State signed for the F-2, F-3, and F-4 projects (id., p. 22).

In that Bay State has identified at least three other possible supply options which were available during Boundary negotiations, the Siting Council cannot accept the Company's contention that it possessed no "viable alternatives" (Exh. HO-10). Rather, the Siting Council finds that the Company has identified and analyzed a reasonable range of practical alternatives to the projects selected. Accordingly, the Siting Council finds that the Company has complied with that part of Condition Nine related to cost studies for the Boundary/INGS and the F-4 expansion projects.

Although Bay State did not compare the Boundary/INGS or F-4 expansion projects to C&LM when decisions were made to pursue those projects, Bay State has adequately demonstrated that conservation is not a cost effective option and that load management is already being pursued to the extent practical. Therefore, the Siting Council finds that the Company has established that the Boundary/INGS and F-4 expansion projects represent least-cost additions to the Company's supply plan.

The Siting Council notes, however, that although Bay State's witness, Mr. Ellis, testified that "Bay State had a very clear understanding of why it entered into each one of these projects" (Exh. BSG-4, p. 23), this understanding was documented through the testimony of Company management. 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.

c. Portland Gas Pipeline Project

The Company discussed the supply alternatives considered before entering into the Portland Gas Pipeline project (Exh. BSG-4, pp. 34-36). Options considered included new increments of pipeline supply from Algonquin and Tennessee, LNG from DOMAC, additional use of LP-air gas, and spot gas purchases. The Company found each of these alternatives to be inferior to the Portland Gas Pipeline project: new Algonquin supplies were not available (id., p. 34); Tennessee's CD-6 expansion project involved too many delays to remain practical (id.); DOMAC LNG and propane were too expensive when compared to the Portland Gas Pipeline gas (id., p. 35); and spot purchases, according to the Company, did not constitute a substitute for long-term firm gas supply (id., pp. 35-36).

The Company also provided documentation comparing "the 100 percent load factor delivered price of the gas which would have been received from the Portland Gas Pipeline project if the project had been in effect during the period from October 1985 through August 1987" to demonstrate the continuing cost effectiveness of this gas supply (id., p. 36, Attachment 4). The Company asserted that the 100 percent load factor calculations were appropriate because during any time period in which the Company will be contracting for Portland Gas Pipeline gas supplies, it will be contracting for those supplies (and all those against which they were compared) at a 100 percent load factor (Tr. III, pp. 32-33).

In support of its decision to proceed with the Portland Gas Pipeline project, Bay State identified certain reliability advantages of the project including (1) access to Canadian supplies which are backed up with reserves more substantial than those typically available domestically, (2) direct access to Canadian suppliers with no reliance on third party actions, (3) a backfeed into the service territory of Bay State's Maine subsidiary, and (4) potential access to offshore gas supplies from the Sable Island, Nova Scotia area once market conditions permit development of those reserves (Exh. BSG-4, pp. 31-33).

The Siting Council finds that these combined responses constitute a comparison of the costs of the Portland Gas Pipeline project with a reasonable range of practical supply alternatives. Accordingly, the Siting Council finds that Bay State has complied with that part of Condition Nine related to cost studies for the Portland Gas Pipeline project.

Although Bay State did not compare the Portland Gas Pipeline project to C&LM at the time the decision was made to pursue that project, Bay State has adequately demonstrated that conservation is not a cost effective option and that load management is already being pursued to the extent practical. Therefore, the Siting Council finds that the Company has established that the Portland Gas Pipeline project represents a least-cost addition to the Company's supply plan.

2. Least-Cost Planning Process

a. Comparison of Alternatives on an Equal Footing

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 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 plan minimizes cost, the Siting Council also evaluates whether the company's supply planning process adequately considers alternative resource additions, including demand-side options, on an equal basis. Berkshire Gas Company, EFSC 86-29, p. 33 (1987); Fall River Gas Company, 15 DOMSC 97, 115 (1986).

In this case, the Company provided analyses showing how it evaluates the costs and benefits of Company-sponsored conservation strategies against the costs and benefits of obtaining new supplies (Exh. BSG-5, pp. 13-19, Attachments 5-9). The Company also described its analyses of the various types of load management programs it either practices or has considered (id., pp. 10-13). The Company's witness, Mr. Gulick, testified that such studies are used by the Company when it evaluates new gas supply possibilities and that such studies would be re-examined and re-assessed if price conditions in the gas market were changing in such a manner as to make conservation a more cost-effective alternative (Tr. III, pp. 82-84).

Accordingly, the Siting Council finds that the Company has established that its planning process incorporates conservation and load management and therefore treats all resource options on an equal footing.

b. Planning Process Results

Throughout this proceeding, the Company stated that its assumptions, methodologies, and decisions ensure that the Company will meet sendout requirements in a least-cost manner. Several characteristics of Bay State's planning process support these assertions.

First, the Company discussed the decisionmaking processes which resulted in three new gas supply projects which will be added during the forecast period. Bay State has demonstrated that the three projects constitute least-cost additions to the Company's supply plan (see Section III.E.1, supra). Second, the Company's design year supply planning strategy was found to reduce costs without sacrificing an adequate gas supply (see Section II.D.2, supra). Finally, the Company's witness, Mr. Ellis, testified that the Company follows a practice of supplanting gas supplies which have a high commodity charge and a low demand charge with equivalent volumes of spot purchases during those times when the commodity cost of the spot gas is lower than that of the supply being replaced (Tr. III, p. 33).

Based on the foregoing, the Siting Council finds that the Company has demonstrated that it operates pursuant to a minimally acceptable supply planning process.

In making this finding, the Siting Council cannot ignore the substantial deficiencies in Bay State's supply planning process since this planning process is not structured so as to ensure that supply-planning decisions will consistently result in least-cost supply. First, Bay State neglects to document formally all of its supply planning decisions (see Section III.E.1.b, supra). Second, although the Company's design year planning process reduces cost, the Siting Council previously found (see Sections II.C.2.e and II.C.2.f, supra) that the Company's choice of its design year and design day standards were not based on a comprehensive analysis of the tradeoffs between cost and reliability. Next, while Bay State provided an analysis showing that its supply decisions resulted in the addition of the least-cost supply options, it failed to demonstrate that demand-side options were considered at the time such decisions were made (see Sections III.E.1.b and III.E.1.c, supra). Finally, even though Mr. Ellis testified that the Company plans to utilize new, more sophisticated cost-comparison techniques in the future, (id., pp. 34-35), Mr. Ellis described neither the types of analyses the Company would develop nor the circumstances under which the Company would apply any such techniques.

In sum, 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.

3. Conclusions

Based on the foregoing, the Siting Council finds that (1) the Company has complied with that portion of Condition Nine of the previous Siting Council decision pertaining to the submission of cost studies, (2) the Company has established that the Boundary/INGS, F-4 Expansion, and Portland Gas Pipeline projects represent least-cost additions to the Company's supply plan, and (3) the Company has adequately considered conservation and load management.

Accordingly, the Siting Council finds that the Company has established that its supply plan ensures a least-cost energy supply.

F. Summary

In summary, the Siting Council has found that Bay State has complied with Conditions Six, Seven, and Nine of its last decision.

The Siting Council has also found that the Company's supply plan is adequate and that this supply plan ensures a least-cost energy supply.

Accordingly, the Siting Council approves Bay State's 1986 supply plan.

IV. DECISION AND ORDER

The Siting Council hereby APPROVES the sendout forecast and supply plan filed by the Bay State Gas Company as its First Supplement to its Third Long-Range Forecast of Natural Gas Requirements and Resources.

The Siting Council ORDERS 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.

The Siting Council FURTHER ORDERS 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.

The Siting Council FURTHER ORDERS the Company to include in its next filing a cold-snap analysis.

The Siting Council FURTHER ORDERS the Company to file its next supplement on September 1, 1988.

Robert D. Shapiro

Robert D. Shapiro
Hearing Officer

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of November 12, 1987, by the members and designees present and voting: Chairperson Sharon M. Pollard (Secretary of Energy Resources); Barbara Anthony (for Paula W. Gold, Secretary of Consumer Affairs and Business Regulation); Stephen Roop (for James S. Hoyte, Secretary of Environmental Affairs); Fred Hoskins (for Joseph D. Alviani, Secretary of Economic and Manpower Affairs). Ineligible to vote: Stephen Umans (Public Electricity Member). Absent: Madeline Varitimos (Public Environmental Member); Dennis J. LaCroix (Public Gas Member); Joseph W. Joyce (Public Labor Member).

Sharon M. Pollard

Sharon M. Pollard
Chairperson

November 12, 1987
Date

TABLE 1

Bay State Gas Company

Forecast of Sendout by Class

Brockton	1985-86 (BBtu)	1986-87 (BBtu)	1990-91 (BBtu)
Residential Heating	7,424	7,632	8,580
Residential General	428	420	341
Commercial	4,387	4,523	4,968
Industrial	1,127	907	1,030
Total*	13,783	13,951	15,441
Lawrence			
Residential Heating	3,544	3,836	4,673
Residential General	166	161	112
Commercial	1,517	1,653	1,857
Industrial	921	808	816
Total*	6,418	6,630	7,662
Springfield			
Residential Heating	5,810	5,972	6,442
Residential General	535	528	458
Commercial	3,720	3,658	3,904
Industrial	1,035	893	1,083
Total*	14,532	14,338	15,061

*Includes Company-Use and UFG

Source: Exh. HO-2, G-1 thorugh G-5

TABLE 2

Bay State Gas Company

Pipeline Gas and Storage Services

Contract	AVL/ACQ (BBtu)	MDQ (BBtu)
Algonquin		
F-1	9,027.2	33.4
F-4	1,681.2	4.5 (86-87)
	2,076.9	5.6 (11/01/87 Start)
WS-1	1,091.9	18.2
STB	676.9	7.5
SS3	723.6	7.2
Granite State		
CD-1	26,984.6	82.2 (11/01/86 Start)
	27,663.9	84.1 (11/01/87 Start)
	34,839.1	103.8 (11/01/88 Start)
GSS-1	1,622.7	14.7
S-1	1,898.1	14.9 Firm
		1.8 Best Efforts

Source: Exh. HO-1, Table G-24 and Exh. HO-5.

TABLE 3

Bay State Gas Company

Comparison of Resources and Requirements
Normal Year - Heating Season
Base Case
(in BBtu)

Requirements	1986-87	1987-88	1988-89	1989-90	1990-91
Firm Sendout	21,948	22,594	23,237	23,879	24,394
Off-System	1,655	1,655	1,475	1,475	1,475
Interruptible	3,626	5,303	5,581	5,581	5,581
Fuel Reimbursement	147	149	149	149	149
Total Requirements	27,375	29,701	30,441	31,083	31,598
Resources					
Pipeline					
Granite CD-1	12,418	12,699	15,667	15,667	15,667
Granite CD-1 (int.)	0	1,187	0	0	0
Algonquin F-1	5,049	5,049	5,049	5,049	5,049
Algonquin F-4	696	859	859	859	859
Algonquin (int.)	0	0	0	0	0
Algonquin WS	1,092	1,092	1,092	1,092	1,092
Total	19,253	20,885	22,667	22,667	22,667
Underground Stor.					
GSS-1	1,623	1,623	1,623	1,623	1,623
S-1 firm	1,693	1,693	1,693	1,693	1,693
S-1 (int.)	205	205	205	205	205
STB	677	677	677	677	677
SS3	724	724	724	724	724
Total	4,921	4,921	4,921	4,921	4,921
Supplementals					
Bay State LNG	157	157	157	157	157
DOMAC LNG	1,398	1,398	1,398	1,398	1,398
Firm Propane	985	488	290	390	590
Other	660	1,851	1,008	1,550	1,865
Total	3,200	3,894	2,854	3,495	4,010
Total Resources	27,375	29,701	30,441	31,083	31,598

Source: HO-1, Table G-22N

TABLE 4

Bay State Gas Company

Comparison of Resources and Requirements
Normal Year - Non-heating Season
Base Case
(in BBtu)

	1986-87	1987-88	1988-89	1989-90	1990-91
Requirements					
Firm Sendout	10,544	10,826	11,089	11,368	11,225
Off-System	774	774	769	769	769
Interruptible	12,701	18,673	19,745	19,745	19,745
Underground Refill	4,921	4,921	4,921	4,921	4,921
Total Requirements	28,940	35,194	36,525	36,804	36,960
Resources					
Pipeline					
Granite CD-1	14,567	14,965	19,172	19,172	19,172
Granite CD-1 (int.)	2,000	1,683	2,000	2,000	2,000
Algonquin F-1	3,979	3,979	3,979	3,979	3,979
Algonquin F-4	986	1,218	1,218	1,218	1,218
Algonquin (int.)	2,000	2,000	2,000	2,000	2,000
Algonquin WS	0	0	0	0	0
Total	23,532	23,845	28,369	28,369	28,369
Supplementals					
Bay State LNG	223	223	223	223	223
DOMAC LNG	1,212	1,212	1,212	1,212	1,212
Firm Propane	0	0	0	0	0
Other	3,974	9,915	6,721	7,001	7,157
Total	5,408	11,350	8,156	8,435	8,592
Total Resources	28,940	35,194	36,525	36,804	36,960

Source: Exh. HO-1, Table G-22N

TABLE 5

Bay State Gas Company

Comparison of Resources and Requirements
Design Year - Heating Season
Base Case
(in BBtu)

Requirements	1986-87	1987-88	1988-89	1989-90	1990-91
Firm Sendout	24,335	25,056	25,775	26,491	27,069
Off-System	2,202	2,202	1,959	1,959	1,959
Interruptible	1,008	1,087	2,064	1,515	1,269
Fuel Reimbursement	147	149	149	149	149
Total Requirements	27,692	28,495	29,947	30,113	30,447
Resources					
Pipeline					
Granite CD-1	12,418	12,699	15,667	15,667	15,667
Granite CD-1 (int.)	0	1,187	0	0	0
Algonquin F-1	5,049	5,049	5,049	5,049	5,049
Algonquin F-4	696	859	859	859	859
Algonquin (int.)	0	0	0	0	0
Algonquin WS	1,092	1,092	1,092	1,092	1,092
Total	19,254	20,886	22,667	22,667	22,667
Underground Stor.					
GSS-1	1,623	1,623	1,623	1,623	1,623
S-1 firm	1,693	1,693	1,693	1,693	1,693
S-1 (int.)	205	205	205	205	205
STB	677	677	677	677	677
SS3	724	724	724	724	724
Total	4,921	4,921	4,921	4,921	4,921
Supplementals					
Bay State LNG	157	157	157	157	157
DOMAC LNG	1,398	1,398	1,398	1,398	1,398
Storage Propane	320	320	320	320	320
Firm Propane Purchase	985	488	290	390	590
Spot Propane	657	325	193	260	393
Other	0	0	0	0	0
Total	3,517	2,688	2,359	2,525	2,859
Total Resources	27,692	28,495	29,947	30,113	30,447

Source: Exh. HO-1, Table G-22D

TABLE 6

Bay State Gas Company

Comparison of Resources and Requirements
Design Year - Non-heating Season
Base Case
(in BBtu)

	1986-87	1987-88	1988-89	1989-90	1990-91
Requirements					
Firm Sendout	10,544	10,826	11,089	11,368	11,525
Off-System	1,174	1,174	1,169	1,169	1,169
Interruptible	12,701	18,673	19,745	19,745	19,745
Underground Refill	4,921	4,921	4,921	4,921	4,921
Propane Refill	320	320	320	320	320
Total Requirements	29,660	35,914	37,245	37,524	37,681
Resources					
Pipeline					
Granite CD-1	14,567	14,965	19,172	19,172	19,172
Granite CD-1 (int.)	2,000	1,683	2,000	2,000	2,000
Algonquin F-1	3,979	3,979	3,979	3,979	3,979
Algonquin F-4	986	1,218	1,218	1,218	1,218
Algonquin (int.)	2,000	2,000	2,000	2,000	2,000
Algonquin WS	0	0	0	0	0
Total	23,532	23,845	28,369	28,369	28,369
Supplementals					
Bay State LNG	223	223	223	223	223
DOMAC LNG	1,212	1,212	1,212	1,212	1,212
Firm Propane	320	320	320	320	320
Other	4,374	10,315	7,122	7,401	7,557
Total	6,129	12,070	8,876	9,155	9,312
Total Resources	29,660	35,914	37,245	37,524	37,681

Source: Exh. HO-1, Table G-22D

TABLE 7

Bay State Gas Company

Comparison of Resources and Requirements
Peak Day
Base Case
(in BBtu)

Requirements	1986-87	1987-88	1988-89	1989-90	1990-91
Total Requirements	286.8	295.6	304.2	312.9	320.0
Resources					
Pipeline					
Granite CD-1	82.2	84.1	103.8	103.8	103.8
Algonquin F-1	33.4	33.4	33.4	33.4	33.4
Algonquin F-4	4.5	5.6	5.6	5.6	5.6
Algonquin WS	18.2	18.2	18.2	18.2	18.2
Total	138.3	141.3	161.0	161.0	161.0
Underground Stor.					
GSS-1/S-1	14.9	14.9	14.9	14.9	14.9
Total	14.9	14.9	14.9	14.9	14.9
Supplementals					
Bay State LNG	122.2	122.2	122.2	122.2	122.2
DOMAC LNG	0	0	0	0	0
Propane Air	110.0	110.0	110.0	110.0	110.0
Other	10.0	0	0	0	0
Total	242.2	232.2	232.2	232.2	232.2
Total Resources	395.4	388.4	408.1	408.1	408.1

Source: Exh. HO-1, Table G-23

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Northeast Energy Associates for Approval to Construct a Bulk Generating Facility

EFSC 87-100

FINAL DECISION

Robert Shapiro
Hearing Officer
December 18, 1987

On the Decision:

Susan F. Tierney
William S. Febiger

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The Energy Facilities Siting Council hereby APPROVES subject to conditions the petition of Northeast Energy Associates to construct a bulk generating facility and ancillary facilities in the Commonwealth of Massachusetts.

I. OVERVIEW

A. Summary of the Proposed Project and Facilities

Northeast Energy Associates ("NEA") has proposed to construct a 300-megawatt[1] ("MW") dual-fuel combined-cycle cogeneration facility on an industrially zoned site in the Town of Bellingham, Massachusetts (Exh. HO-1, pp. I-1 to I-2; Exhs. HO-26, HO-14A, HO-CFO-1; Tr. II, pp. 35-37). NEA's petition includes a request to construct the generating facility, along with certain ancillary facilities: a transmission line to interconnect the power plant with an existing 345 kilovolt ("kV") bulk power transmission line; a gas pipeline to enable the power plant to receive its primary fuel, natural gas, from an existing interstate gas pipeline; and facilities for the storage of distillate fuel oil (Exh. HO-1, pp. I-1, I-2, II-1 to II-5, II-11; Exh. HO-1A).

For the proposed Bellingham generating facility, NEA has received certification[2] from the Federal Energy Regulatory Commission ("FERC") that the project constitutes a "Qualifying Facility" ("QF") under the Public Utilities Regulatory Policies Act of 1978 ("PURPA"), which requires electric utility companies to purchase power from QFs

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1/NEA asserts that the maximum output of the plant will be 306.5 MW if the plant is required to reduce its nitrogen oxide emissions below the 42 parts-per-million level (Tr. II, p. 36).

2/FERC granted QF status to the NEA project in December 1986 (Exh. HO-B-14.B). Due to subsequent changes in the specific technology proposed to be used at the facility, NEA has applied to FERC for recertification as a QF; the FERC order is pending (Exhs. HO-14, HO-14A; Tr. II, p. 7).

such as NEA for a price at or below the utility's avoided cost of production (Exh. HO-1, p. I-3). The FERC certification of NEA as a QF is based upon a finding that NEA will provide sufficient steam sales to customers so as to qualify as a cogeneration facility. 18 CFR 292.203.

NEA has signed long-term power sales agreements with three Massachusetts utility companies, Boston Edison Company ("BECo"), Commonwealth Electric Company ("Comm Electric") and Montaup Electric Company[3] ("Montaup"), for 150 MW of the facility's full 300-MW output (Exh. HO-1, pp. VII-1 to VII-10; Exhs. HO-4, HO-5, HO-6). The three signed agreements begin with the start of NEA's commercial operation, now scheduled for January 1, 1990 (Exh. HO-1, pp. VII-1, VII-5, VII-6; Exh. HO-B-7; Tr. II, pp. 59-60). NEA asserts that it expects to sign contracts with these three companies for additional power sales totalling 120 MW (Exh. HO-B-8; Tr. II, pp. 41-44) and that it intends to market any remaining portion of the plant's output to utility companies in New England (Exh. HO-N-4).

The NEA project is the first bulk power generating facility presented by a non-utility company developer to the Energy Facilities Siting Council ("Siting Council") for approval. The project developer, NEA, is a Massachusetts limited partnership with a Massachusetts corporate general partner, Intercontinental Energy Corporation -- all of which entities are owned by the Roy family of Cohasset, Massachusetts (Exh. HO-1, p. II-1; Exhs. HO-B-1, HO-B-2, HO-B-3, HO-B-5; Tr. I, p. 73). The principal shareholders and employees of NEA are engaged in other energy-development projects in the United States and abroad (Exhs. HO-B-2, HO-B-3, HO-B-4, HO-B-5; Tr. I, pp. 76-90; Tr. II, pp. 5-6, 23-33).

3/Montaup Electric Company is a generation and transmission company that sells power at wholesale to Eastern Edison Company, a retail electric company in Massachusetts, and Blackstone Valley Electric Company in Rhode Island. All of these companies are subsidiaries of Eastern Utilities Associates.

B. Procedural History

On June 22, 1987, NEA filed its Petition for Approval to Construct a Bulk Generating Facility (Exh. HO-1). This petition included NEA's proposal for a 300-MW dual-fuel combined-cycle cogeneration facility, a gas pipeline, and facilities for storage of fuel oil.

On July 20, 1987, NEA filed an amendment to its petition, stating that it intended to construct an electric transmission line to interconnect the proposed plant with existing transmission lines (Exh. HO-1A).

On July 23, 1987, the Siting Council conducted a public hearing in the Town of Bellingham. In accordance with the directions of the Hearing Officer, NEA provided notice of the public hearing and adjudication.

Petitions to intervene were filed by Bay State Gas Company ("Bay State"), the Box Pond Association, and the Franklin Environmental Education Trust ("Franklin"). In addition, the Winiker Realty Trust ("Winiker") filed a petition to participate as an interested party.

On August 12, 1987, NEA filed its response in opposition to Franklin's petition. On August 19, 1987, Franklin filed a motion to amend its petition to intervene to add 23 residents of the Town of Bellingham ("Bellingham Group").

On August 21, 1987, the Hearing Officer conducted a pre-hearing conference (1) to rule on the petitions to intervene as a party and petition to participate as an interested party and (2) to establish a procedural schedule for the remainder of the proceeding. At this conference, the Hearing Officer granted the petitions of Bay State, Box Pond Association, and Winiker. The Hearing Officer denied Franklin's motion to amend, noting that Franklin had failed to demonstrate that Franklin and Bellingham Group had similar interests in the proceeding. The Hearing Officer, however, granted Bellingham Group's motion for leave to file a late petition to intervene. The Hearing Officer granted Bellingham Group's petition to intervene, but limited the intervention to environmental issues only.[4] Finally, Franklin withdrew its petition to intervene.

On September 29, 1987, the Hearing Officer conducted a second pre-hearing conference regarding NEA's objections to certain information requests of Bellingham Group.

The Siting Council conducted six evidentiary hearings. NEA presented ten witnesses: Henry Lee, Executive Director of Harvard University's Energy and Environmental Policy Center, who testified regarding need for the proposed facility; Stephen Roy, NEA, who testified regarding project description; Peter Roy, NEA, who testified regarding project financing and ancillary facilities; Wayne J. Oliver, R. J. Rudden Associates, who testified regarding costs of alternative technologies; John Dalton, R. J. Rudden Associates, who testified regarding environmental impacts of alternative technologies; Donald J. DiCristofaro, Sigma Research Corporation, who testified regarding air quality impacts; Dana Hooper, Harris, Miller, Miller and Hansen, Inc., who testified regarding noise impacts; Martin Mitchell, the B.S.C. Group, who testified regarding waste disposal, wildlife, and wetland impacts; Michael S. Healey, the B.S.C. Group, who testified regarding water impacts; and Dorsey Lynch, First Boston Corporation, who testified regarding project financing. Bay State presented Charles T. Ellis, Senior Vice President, who testified on the contract between NEA and Bay State. Box Pond Association presented Karen Straight, Secretary, who testified regarding the proposed facility's impact upon the Box Pond. Bellingham Group did not present any witnesses.

The Hearing Officer entered 161 exhibits in the record,[5]

4/Bellingham Group filed its motion to intervene pursuant to the terms of G.L. c. 30A, sec. 10A, which provides for intervention limited to environmental issues only.

5/NEA requested that certain documents (Exhs. HO-20, HO-26, HO-27, HO-28, HO-B-3, HO-B-5, HO-B-9.C, HO-B-9.D(4), HO-B-9.D(5), HO-B-9.D(15), HO-B-9.D(16), HO-B-9.D(31), HO-B-9.D(32), HO-B-9.D(34), HO-B-9.D(35), HO-B-9.D(36), HO-B-9.D(39), HO-B-9.G, HO-B-10.B, and portions of HO-18) receive protective treatment. The Hearing Officer granted this request and allowed intervenors access to these documents, pursuant to 980 CMR 4.05(2)(d), if a protective agreement with NEA were signed (Tr. 9/29/87, pp. 20-21).

largely composed of responses to information and record requests. NEA offered 16 exhibits into the record, while Box Pond Association entered one exhibit in the record.

Pursuant to a briefing schedule established by the Hearing Officer, NEA filed its brief ("NEA Brief") on November 17, 1987. On November 18, 1987, Bellingham Group filed a brief ("Bellingham Brief").

On November 24, 1987, the Box Pond Association filed a reply brief specifically addressing issues raised in Bellingham Group's brief. On that same date, NEA filed a motion to strike the brief of Bellingham Group. Bellingham Group did not file a response to NEA's motion.

On December 4, 1987, the Hearing Officer issued a Procedural Order granting NEA's motion to strike, stating that facts and arguments contained in Bellingham Group's brief were not in the record. In the December 4, 1987 Order, the Hearing Officer ruled that the reply brief of Box Pond Association be stricken, as it also contained information and argument outside of the record.

C. Jurisdiction

NEA's petition to construct a bulk generating facility and ancillary facilities is filed in accordance with G.L. c. 164, sec. 69H, which requires the Siting Council to ensure a necessary energy supply for the Commonwealth with minimum impact on the environment at the lowest possible cost, and G.L. c. 164, sec. 69I, requiring electric companies to obtain Siting Council approval for construction of proposed facilities at a proposed site before a construction permit may be issued by another state agency.

As a combined-cycle cogeneration facility designed for operation at 300 MW, NEA's proposed generating unit falls squarely within the first definition of "facility" set forth in G.L. c. 164, sec. 69G:

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

At the same time, NEA's proposal to construct a transmission line, gas pipeline, and oil storage facilities, falls within the third definition of "facility" set forth in G.L. c. 164, sec. 69G:

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

In accordance with G.L. c. 164, sec. 69H, before approving an application to construct facilities, the Siting Council requires applicants to justify facility proposals in three phases. First, the Siting Council requires the applicant to show that the facilities are needed (see Section II.A, infra). Next, the Siting Council requires the applicant to present plans that satisfy the previously identified need and that are superior to alternative plans in terms of cost and environmental impact (see Section II.B, infra). Finally, the Siting Council requires the applicant to show that the proposed site for the facility is superior to the alternate site in terms of cost, environmental impacts and reliability of supply (see Section III, infra). Boston Edison Company, 13 DOMSC 63, 67-68 (1985).

II. ANALYSIS OF THE PROPOSED PROJECT

A. Need Analysis

1. Standard of Review

a. Standards Applied in Previous Reviews of Need in Utility-Company Facility Proposals

i. Need For Facilities to Meet Reliability and Economic Objectives

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 power resources[6] to meet reliability or economic efficiency objectives.[7] The Siting Council therefore must find that additional power resources are needed as a prerequisite to approving proposed energy facilities. Boston

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6/In this discussion, "additional power resources" is used generically to encompass generating facilities, transmission facilities, capacity or energy associated with power sales agreements, and energy or capacity savings associated with conservation and load management.

7/The Siting Council also evaluates the need for additional power resources in the context of its reviews of electric utilities' long-range forecasts of demand and supply. G.L. c. 164, sec. 69I. In such reviews, the Siting Council determines whether a company's supply plan is adequate to meet projected customer requirements in both the short run and long run under a reasonable range of contingencies. See Boston Edison Company, 15 DOMSC 241, 300-302 (1987).

Edison Company, 13 DOMSC 63, 67-68 (1985).

In so doing, the Siting Council is guided by G.L. c. 164, sec. 69J, which states that the Siting Council shall approve a forecast,

> If [the Siting Council] determines that it meets the following requirements: .... projections of the demand for electric power,... and of the capacities for existing and proposed facilities are based on substantially accurate historical information and reasonable statistical projection methods,... projections relating to service area, facility use and pooling or sharing arrangements are consistent with such forecasts of other companies subject to this chapter as may have already been approved and reasonable projections of activities of other companies in the New England area; plans for expansion and construction of the applicant's new facilities are consistent with current health, environmental protection, and resource use and development policies as adopted by the commonwealth; and are consistent with the policies stated in [c. 164] section sixty-nine H to provide a necessary power supply for the commonwealth with a minimum impact on the environment at the lowest possible cost.

Further, the Siting Council is guided by precedents established in previous decisions on utility-company proposals to construct major energy facilities in the Commonwealth. Importantly, prior to this case, the Siting Council has never addressed a proposal to construct an energy facility in Massachusetts offered by any entity other than a utility company as defined in G.L. c. 164, sec. 1. As such, Siting Council decisions on facility proposals have applied standards that were appropriate in reviewing facilities proposed by utility companies.

In previous decisions regarding utility-company facility proposals, the Siting Council has found that need for new facilities may be established on various grounds: need for additional capacity to meet reliability objectives, and need for new energy supplies for economic efficiency purposes. In fact, most of these need determinations have been grounded in decisions that considered transmission line proposals, as in Boston Edison Company, 13 DOMSC 63, 67-81 (1985), although the Siting Council has also found that new facilities were needed in the case of a proposed electric generating facility, Massachusetts Municipal Wholesale Electric Company, 1 DOMSC 101 (1977), Massachusetts Municipal Wholesale Electric Company, 1 DOMSC 52 (1976), proposed gas pipelines, such as in Boston Gas Company, 11 DOMSC 159 (1984), proposed liquefied natural gas facilities, such as in Berkshire Gas Company, 1 DOMSC 24 (1976), and proposed propane facilities, such as in Boston Gas Company, 8 DOMSC 1 (1982).

In evaluating the need for new energy facilities or other power resources to provide additional capacity to a utility system, the Siting Council has evaluated the reliability of the system if new load growth or certain contingencies occured. With respect to new load growth, the Siting Council has found that additional capacity is needed where projected future capacity available to the system is inadequate to satisfy projected load and reserve requirements. Cambridge Electric Light Company, 15 DOMSC 187, 211-212 (1986); Massachusetts Electric Company, 13 DOMSC 119, 137-138 (1985). With regard to contingencies, the Siting Council has found that new capacity is needed in order to ensure that service to existing firm customers can be maintained in the event that a reasonably likely contingency occurs. Nantucket Electric Company, 15 DOMSC 363, 380-383 (1987); Massachusetts Electric Company, 13 DOMSC 119, 137 (1985); Boston Edison Company, 13 DOMSC 63, 70-73 (1985); Massachusetts Municipal Wholesale Electric Company, 1 DOMSC 101 (1977). In Massachusetts Electric Company, 13 DOMSC 119, 137 (1985), the Siting Council found that New England needed to add a significant amount of new capacity for reliability purposes within a decade under "almost every combination of reasonable contingencies."

The Siting Council also has determined in some instances that utilities need to add power resources primarily for economic efficiency purposes rather than to meet reliability objectives. The Siting Council has found that a utility company's proposed energy facility was needed principally for providing economic energy supplies relative to a system without the proposed facility. Massachusetts Electric Company, 13 DOMSC 119, 178-179, 183, 187, 246-247 (1985); Boston Gas Company, 11 DOMSC 159, 166-168 (1984).

Additionally, in previous cases on utility supply plans or facility proposals, the Siting Council has implemented important energy and resource-use and -development policies in its determinations that the utility needed to minimize its electricity costs through (1) diversifying its fuel mix, Boston Edison Company, 15 DOMSC 287, 302, 350 (1987), Cambridge Electric Light Company, 15 DOMSC 125, 164-165 (1986), Boston Edison Company, 10 DOMSC 203, 241 (1984); (2) reducing the Commonwealth's dependence upon oil, Massachusetts Electric Company, 13 DOMSC 119, 132-133 (1985), Fitchburg Gas and Electric Company, 13 DOMSC 85, 114-115 (1985), Boston Edison Company, 10 DOMSC 203, 241 (1984), Berkshire Gas Company, 6 DOMSC 114, 127 (1981); and (3) increasing its purchases of electricity from small power producers and cogenerators, Massachusetts Municipal Wholesale Electric Company, EFSC 85-1, pp. 40-42 (1987), Cambridge Electric Light Company, 12 DOMSC 39, 82-83 (1985), Massachusetts Municipal Wholesale Electric Company, 11 DOMSC 237, 276, 284 (1984).

ii. Geographic Scope of Need Determination

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 in previous utility-company facility decisions to encompass not only evaluations of specific Massachusetts utilities' need for additional power resources, Boston Edison Company, 13 DOMSC 63, 74 (1985), Hingham Municipal Lighting Plant, 14 DOMSC 7 (1985), but also the consideration of whether proposals to construct energy facilities within the Commonwealth are needed to meet New England's energy needs. Massachusetts Electric Company, 15 DOMSC 241, 273, 281 (1986); Massachusetts Electric Company, 13 DOMSC 119, 129-131, 133, 138, 141 (1985); Massachusetts Electric Company, 2 DOMSC 1, 4-6 (1977).

In so doing, the Siting Council has fulfilled the requirement of G.L. c. 164, sec. 69J, which recognizes the interconnected nature of the region's generation and transmission system and the reliability and economic benefits that flow to Massachusetts from the state's utilities' participation in the New England Power Pool ("NEPOOL").

b. Standards for Determining Need in Non-Utility-Company Facility Proposals

NEA submits that the Siting Council should modify its standard of review where a non-utility-company has proposed to construct a QF energy facility in the Commonwealth (NEA Brief, pp. 6-12).

NEA cites the standards applied by the Siting Council in Massachusetts Electric Company, 13 DOMSC 119 (1985) (the "Hydro Quebec" case), where NEA asserts that the petitioner was required to demonstrate "that the proposed project is necessary to meet electric generating capacity and energy needs for New England and the customers of the purchasing utility companies" (NEA Brief, p. 6). Although NEA contends that it meets all standards set forth in the Hydro Quebec case, it submits that "standards set for a large utility sponsored project may be unduly rigorous for smaller QF projects sponsored by individual developers" (id., pp. 6-7). NEA argues, however, that (1) there are "policy reasons and equity considerations that favor less stringent standards for a QF project" (id., p. 7), and (2) "an appropriate standard of review must be instituted that balances the Council's mandate with the policy of encouraging QF capacity and the unique characteristics and problems of QF projects" (id., p. 9).

In support of the more narrow standard, NEA argues that (1) the Commonwealth has declared a clear policy preference for the development of QF capacity; (2) QF projects differ from utility projects in that the cost of QF power may not exceed the purchasing utility's avoided cost and ratepayers do not bear the risk of QF cost overruns or poor plant performance; (3) QF developers have fewer resources than utility developers of projects; and (4) QF projects over 100 MW in size, which must receive Siting Council approval, have a competitive disadvantage relative to small QF projects since smaller projects need not undergo Siting Council review (id., pp. 6-9).

NEA proposes that, with regard to QF projects, the Siting Council should "require a showing of need that is substantially the same as that in Hydro-Quebec. Need could be demonstrated on either a regional, state or individual company basis. The analysis should be flexible as it was in the Hydro-Quebec decision and take into consideration reasonable demand and supply contingencies" (id., p. 10).[8]

The Siting Council agrees that the character of QF facility proposals filed by non-utility-company developers to meet reliability concerns or economic efficiency goals of a regional power market or a specific utility purchaser warrants some modification of the standard of review for need that has been established in previous cases.

With respect to need, where a non-utility-company developer seeks to construct a jurisdictional QF facility (or a jurisdictional facility supporting a QF project) principally for a single specific utility purchaser, the Siting Council requires the applicant to demonstrate that the utility needs the facility to address reliability concerns or economic efficiency goals. Where a non-utility developer has proposed a QF facility for a number of power purchasers that include purchasers that are as yet unknown, or for purchasers with retail service territories outside of Massachusetts, need may be established on a regional basis. Regional need may also be based on either reliability or economic efficiency grounds.

However, the Siting Council's statute also requires a showing that the proposed facility ensures an adequate supply of energy for the Commonwealth. Therefore, the non-utility developer that proposes a QF facility to serve a regional need must also demonstrate to the Siting Council that the proposed facility benefits Massachusetts -- that is, it offers reliability or economic efficiency benefits to the Commonwealth in sufficient magnitude so that the construction of an energy facility in the state is consistent with the energy needs and resource use and development policies of the Commonwealth.

In a case where a non-utility developer has proposed to construct

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8/NEA proposes four other standards for the Siting Council to adopt in reviewing QF projects and to apply specifically in the instant case (id., pp. 10-11). As these proposed standards relate to cost and environmental impact determinations, the Siting Council describes and considers NEA's proposals in Sections II.B.1 and III.A, infra.

a QF generating facility in Massachusetts to serve a number of power purchasers, some as yet unknown, the Siting Council evaluates the need for the proposed QF facility first in New England and secondly in Massachusetts.

If NEA shows that it is proposing to construct a QF facility in Massachusetts to serve a number of power purchasers in the region, some as yet unknown, then it must demonstrate (1) that New England needs the proposed additional power resources for reliability or economic efficiency purposes in the proposed time period, and (2) that Massachusetts is likely to receive reliability or economic efficiency benefits from the proposed additional power resources during the same time frame.

2. Status of NEA's Power Sales Commitments

At the time of hearing, only half of the output of NEA's proposed 300-MW plant was under signed and approved power-purchase agreements with three Massachusetts companies: Boston Edison, Comm Electric and Montaup (Exhs. HO-4, HO-5, H0-6). Of the remaining 150 MW, 80 MW has been bid to and accepted by Boston Edison as part of its "Award Group" of QF bidders (Exhs. HO-B-9.E, HO-B-8.A, and HO-1, p. III-1). Further, NEA has offered an additional 20 MW each to Comm Electric and Montaup (Tr. II, pp. 68-69). Depending upon whether these three companies actually sign contracts with NEA to purchase the offered second increment of NEA's power, and whether these agreements receive necessary regulatory approvals, there will be from 30 to 150 MW that NEA will have available to market to other utility companies in the region[9] (Tr. II, pp. 36-38, 41-44; Tr. V, pp. 169-171).

9/As discussed in Section II.B.2, infra, NEA expects to sign contracts with Boston Edison for the 80 MW and with Comm Electric for the 20 MW, and to sell another 20 MW to Montaup (Tr. II, pp. 41-44). Therefore, NEA's position is that it will most likely have only 30 MW left to market to electric companies in New England (Exh. HO-N-4; Tr. V, pp. 168-169).

Thus, NEA is proposing to construct a facility (1) for providing wholesale electric power to a regional market, and (2) for selling power to several utility companies under agreements that include (a) ones yet to be finalized, signed and approved, and (b) ones with companies with retail service territories outside of Massachusetts.

In light of the foregoing, the Siting Council evaluates whether New England needs the proposed 300 MW of additional power resources for reliability or economic efficiency purposes by the proposed time period of 1990, and whether Massachusetts is likely to receive reliability or economic efficiency benefits from the proposed additional power resource during the same time frame.

3. New England's Need for Additional Power Resources

NEA based its argument that New England needs additional power resources principally upon a reliability rationale. NEA asserts that the region needs additional power resources because projected capacity in New England is inadequate to satisfy the region's projected load and reserve needs (Exh. HO-1, pp. III-1 to III-19).

NEA presented and evaluated the results of various projections of electricity demand and supply in New England (Exh. HO-1, pp. III-2 through III-18; Tr. I, pp. 11-28; Exh. HO-N-1.D). These projections -- developed by entities other than NEA -- include those published in the following documents: (1) the NEPOOL "Forecast Report of Capacity, Energy, Loads and Transmission, 1986-2001" ("1986 CELT Report"), which indicates a long-run growth rate of 2.2 percent per year for NEPOOL's summer peakload electricity demand; (2) the "Contingency Case" developed by the New England Governors' Conference, Inc. in conjunction with NEPOOL member utilities as part of a December 1986 report, which forecasts a four-percent annual growth rate in summer peakload demand between 1987 and 1991, and 3.2 percent annual overall growth rate from 1987 through 2000; and (3) a forecast presented by an independent power producer, Ocean State Power, as part of its 1987 application to the Rhode Island Energy Facilities Siting Board, which indicates a growth rate of three percent annually from 1986 through

1989 and a 1.6 percent per year increase thereafter (Exh. HO-1, pp. III-3, III-12 to III-14; Exhs. HO-N-1.A, HO-N-1.B, HO-N-1.C; Tr. I, pp. 25-28).

Additionally, NEA presented its own "modified" mid-range demand and supply scenario through the year 2000: four percent per year for the period 1987-1991 and NEPOOL's historical growth rate of 2.7 percent annually thereafter (Exh. HO-1, p. III-15; Tr. I, pp. 27-28, 53-54). Finally, NEA evaluated the load and capacity estimates for 1987 through 2002 as published in NEPOOL's 1987 CELT Report (Exh. HO-N-2; Tr. I, pp. 26-29).

Through qualitative analysis and the testimony of its witness, Mr. Lee, NEA discussed the ways in which the assumptions and results of these various electricity demand and supply projections differ, in particular with respect to when each forecast indicates that New England will need to add capacity for reliability purposes[10] (Exh. HO-1, pp. III-11 through III-18; Exh. HO-N-2; Tr. I, pp. 26-33). Mr. Lee criticized the low, short-term electricity growth rates presented in NEPOOL's 1986 and 1987 CELT Reports as being inconsistent with recent trends affecting electricity consumption in the region (Tr. I, pp. 27-29; Exh. HO-N-2). Mr. Lee also asserted that the higher growth rates in the New England Governors' Conference's "Contingency Case"

10/According to the 1986 CELT Report, which does not include NEA's 300 MW as part of the estimate of capacity in New England, NEPOOL needs to add capacity starting in 1990 to meet summer peakload and a 20-percent reserve requirement, assuming Seabrook 1 is not on line, and in 1995 if Seabrook comes on line (Exhs. HO-11 and HO-N-1.A, p. 1). The New England Governors' Conference's short-run "Contingency Case" projections indicate that, assuming Seabrook is not available, New England will need 242 MW of additional capacity in 1989 and 913 MW by 1991; with Seabrook, these projections indicate that new capacity would be needed starting in 1992 (Exh. HO-N-1.B; Exh. HO-1, pp. III-13 to III-17). The Ocean State Power projections indicate need for 439 MW in 1989 and 763 MW by 1990, assuming Seabrook is not available (Exh. HO-1, pp. III-12 to III-17; Exh. HO-N-1.C). Under NEA's modified forecast scenario, 1134 MW of new resources will be needed by 1989 assuming Seabrook is not available, and 892 MW will be needed by 1990 if Seabrook is available (Exh. HO-1, pp. III-11 to III-17).

more accurately reflect these trends (Tr. I, pp. 27-28). Overall, NEA states that these forecasts represent the "likely range" of reasonable estimates of electricity demand in New England (Exh. HO-1, p. III-15).

According to NEA, "the need for new sources of electric power in the region under most scenarios is evident" from the collective results of these forecasts (id., pp. III-17, III-1; Tr. I, p. 34). NEA asserts that under all of the forecast results and scenarios presented and proposed, including the estimates set forth in the 1986 CELT Report and the New England Governors' Conference Report, considerable conservation and load management will occur in the region, but nevertheless New England needs to add a significant amount of capacity starting in the 1988-to-1990 period to meet forecasted load and reserve requirements (Exh. HO-1, pp. III-11 through III-18).

Finally, NEA asserts that uncertainty surrounding Seabrook and Pilgrim reinforces the need for additional power resources in 1990, the proposed start-up date for the NEA project (Exh. HO-1, pp. III-12 to III-19; Tr. I, pp. 14-15). Mr. Lee testified that the likelihood that the 300 MW associated with NEA's proposed project will not be needed in New England in the short run is very low, and that such a circumstance would be the result of an implausible combination of events (Tr. I, pp. 47-51).

NEA submits that New England's need for additional power resources to meet demand and reserve requirements is clear under a reasonable range of demand and capacity scenarios for the region (Exh. HO-1, p. III-19; NEA Brief, p. 15).

NEA presented several forecasts projecting need for additional power resources by 1990. While NEA did not provide its own projections of electricity demand and supply in the region, NEA offered the results of various forecasts prepared recently by industry and government organizations in the region (Exh. HO-1, pp. III-3, III-11 to III-19; Exhs. HO-N-1.A, HO-N-1.B, HO-N-1.C, HO-N-2). NEA also provided an evaluation of the assumptions embedded in these forecasts and a qualitative analysis of how their results might have changed if different assumptions were made about economic growth, population growth, electricity price forecasts, the development of small power production and cogeneration facilities, and the availability of conservation, load management, and the Seabrook and Pilgrim units (Exh. HO-1, pp. II-2 to II-11, II-17 to III-19; Tr. I, pp. 11-51; Exh. HO-N-1.D). According to these forecasts and NEA's sensitivity analysis, New England needs to add new power resources for reliability purposes as early as 1989 and no later than the mid-1990s (Exh. HO-1, p. III-19).

NEA has provided the Siting Council with an acceptable combination of quantitative forecast results and qualitative evaluations. In that NEA has presented a reasonable range of plausible forecasts and has adequately analyzed the sensitivity of forecast results to changes in critical assumptions, the Siting Council finds that NEA has provided projections of the demand for electric power and the capacities of existing and proposed facilities that are based on substantially accurate historical information and reasonable statistical projection methods.

Accordingly, the Siting Council finds that NEA has established that New England needs at least 300 MW of additional power resources for reliability purposes by 1990.

4. Massachusetts' Need for Additional Power Resources

Having established that New England needs at least 300 MW of additional power resources to meet reliability objectives by 1990, the Siting Council determines whether the proposed project is likely to provide reliability or economic efficiency benefits to Massachusetts in that same time frame.

a. Description and Arguments

NEA offers four arguments to demonstrate that Massachusetts would receive reliability or economic efficiency benefits from NEA's proposed project: (1) the contracts that NEA has signed with three Massachusetts utility companies serve as *prima facie* evidence of those companies' need for the power offered by NEA; (2) Massachusetts utilities' purchases of QF power at or below avoided cost, as evidenced by the NEA contracts and bid, serve the economic efficiency and reliability objectives of those utilities' ratepayers; (3) the long-range demand and supply forecasts of Boston Edison, Comm Electric, and Montaup indicate need to add capacity for reliability objectives within the next few years; and (4) the policies of the Massachusetts Department of Public Utilities ("MDPU") and the Executive Office of Energy Resources establish that Massachusetts utilities need to purchase power from QFs consistent with PURPA so as to help ensure an economic and secure power supply.

In support of the first argument, NEA contends that "from the perspective of a wholesaler of any commodity, the existence of signed contracts from financially sound buyers to purchase the commodity is prima facie evidence that there is a guaranteed market. Such contracts also demonstrate that the purchasers of the commodity believe that there is a clear retail market for that power" (Exh. HO-1, pp. III-22, III-23; Tr. I, pp. 54-55).

With regard to the second argument -- that Massachusetts ratepayers will benefit from the power resources associated with the NEA contracts -- NEA provided copies of its signed and approved contracts with three Massachusetts electric companies for sales of energy totalling 150 MW (Exhs. HO-4, HO-5, HO-6, HO-B-17, HO-B-18, HO-CAT-8.A, and HO-1, Sec. VII; Tr. I, pp. 61-62). Both the Boston Edison and Comm Electric contracts call for capacity payments starting in the year these companies project to need to add capacity for reliability purposes in the absence of the NEA contract (Exh. HO-1, pp. III-3, III-7; Exhs. HO-4, HO-5, HO-CAT-8.A). Additionally, NEA documented the 80-MW bid it submitted in response to Boston Edison's Request for Proposals ("RFP") for 200 MW of QF power issued pursuant to the MDPU process established for utility company purchases of power from QFs (Exh. HO-B-9.G). Boston Edison has informed NEA that its 80-MW offer is part of Boston Edison's QF "Award Group" and therefore makes NEA eligible to sign a contract with Boston Edison and to receive payments reflecting its long-run avoided energy and capacity costs (Exhs. HO-B-9.E, HO-B-9.F; Tr. II, pp. 9-11).

By virtue of these existing and expected contracts, NEA asserts that Boston Edison, Comm Electric, and Montaup need to add new power resources for reliability purposes. NEA also notes that its existing and expected contracts provide economic benefits to the ratepayers of Boston Edison, Comm Electric, and Montaup since NEA will sell power to each of these utilities at no risk to ratepayers and at prices that are lower than the company's long-term avoided costs (Exhs. HO-4, HO-5, HO-6, HO-B-9.E, HO-B-9.F, HO-B-9.G, and HO-1, p. III-21).

In support of the third argument, NEA asserts that the long-range forecasts and supply plans of Boston Edison, Comm Electric, and Montaup show that additional power supplies, including the power purchases from the NEA project, "represent part of [the companies'] attempt to avoid the prospect of inadequate reserve margins and a commitment to integrate power from qualifying facilities into their supply plans" (Exh. HO-1, p. III-23). NEA cites the utilities' filings with the Siting Council as well as previous Siting Council decisions. With regard to Boston Edison, NEA refers to a resources-and-requirements table from the Siting Council decision in <u>Boston Edison Company</u>, 15 DOMSC 287, 358 (1987), and asserts that "even with the purchase from Northeast Energy there is still a need for additional power resources" and "in terms of sensitivity analysis, Boston Edison's projections show that the potential contribution of power by the Northeast Energy cogeneration facility by 1989 would be even more important if either demand growth is higher or the company is unable to bring Pilgrim I back of line" (Exh. HO-1, pp. III-23, III-25; Tr. I, pp. 43, 55). In regard to Comm Electric, NEA cites the Siting Council's decision in <u>Cambridge Electric Light, Canal Electric, and Commonwealth Electric Companies</u>, 15 DOMSC 125 (1986), to argue that without additional QF capacity, Comm Electric has projected capacity shortfalls starting in 1989 and that the "25 MW provided by COM/Electric's contract with NEA is needed to ensure that COM/Electric has sufficient capacity to meet its NEPOOL capability responsibility" (Exh. HO-1, pp. III-25 to III-28; Tr. I, pp. 43, 55). Finally, NEA argues that the demand and supply forecast recently filed at the Siting Council by Eastern Utilities Associates shows that under a base case forecast and a contingency case, Montaup needs to add power within the next six years in order to meet forecasted peakload and reserve requirements (Exh. HO-1, p. III-29; Tr. I, p. 65).

Finally, with regard to its fourth argument, NEA asserts that utility contracts with QFs are consistent with the Commonwealth's energy policies. In support, NEA cites the initiative of the Massachusetts Executive Office of Energy Resources to revise the state's regulations governing utility purchases of QF power so as to ensure that cogeneration and small power production facilities "play a vital role in the attainment of a secure, affordable and environmentally sustainable energy future" (Exh. HO-1, p. I-3; Exh. HO-CAT-2.A). NEA's witness, Mr. Lee, testified that the Commonwealth has been encouraging the development of QFs as an alternative to the traditional practice of building large central station generating plants, since QF capacity can be added in small increments with short lead times and thereby reduce ratepayers' risk associated with construction of plants, poor plant performance, and misestimation of future demand in the long run (Tr. I, pp. 44-47, 56, 61-64).

Further, NEA cites a recent MDPU decision in DPU 86-36-A, where the MDPU decided it needed to revise its regulations governing utility purchases of QF power because the MDPU recognized the failure of electric utilities in Massachusetts to incorporate cost-effective QF generation into their supply mix and to consider cost-effective QFs as valid supply planning options (Exh. HO-1, p. III-20). NEA quotes the MDPU as determining that utility contracts with QFs limit ratepayers' exposure because they are protected by the terms of the contracts and are not held responsible for the costs of a power plant if a given QF fails to operate or deliver power. Additionally, ratepayers benefit from the competitive aspects of a solicitation and bidding framework, in that QFs can be expected to reflect competitive pressures in their bid prices (id.).

b. Analysis

The Siting Council considers each of NEA's arguments. With regard to NEA's fourth rationale, the Siting Council recognizes and accepts NEA's contention that the Commonwealth benefits generally from the development of QFs, consistent with the intent of PURPA. NEA submitted sufficient documentation articulating the Commonwealth's policy of instituting regulatory processes and standards that encourage utilities to sign long-term contracts with QFs at or below the utilities' long-run avoided costs, so as to ensure a reliable and economic power supply for the Commonwealth. Accordingly, the Siting Council finds that, consistent with current resource use and development policies of the Commonwealth, ratepayers in Massachusetts benefit economically from the addition of cost-effective QF resources to their utilities' supply mixes.

With regard to NEA's first and second arguments, the Siting Council agrees with NEA that a signed power sales contract between a QF and a utility certainly indicates that the utility company has decided it needs the power from the QF. However, until that contract has been approved by the appropriate reviewing authority (e.g., the MDPU) as actually offering prices at or below the utility's projected avoided costs, or unless the agreement was made pursuant to an approved competitive bidding process that ensures that contracts between a QF and a utility are cost-justified, the Siting Council cannot simply rely on the existence of a signed agreement as evidence of the company's need for economical or reliable power resources.

However, the Siting Council agrees that the existence of a signed and approved power sales agreement between a QF and utility constitutes prima facie evidence of the utility's need for the power for economic efficiency reasons. Further, when these contracts include a capacity payment to the QF, the approved agreement constitutes prima facie evidence of the utility's need for additional power resources for reliability purposes. An approved agreement indicates that the reviewing agency (1) accepts the utility's projection of avoided energy and capacity costs, and (2) finds that the pricing arrangements under the agreement are likely to yield payments to the QF over the life of the contract at or below the utility's avoided costs.

Thus, the Siting Council finds that, by definition, the ratepayers of utilities benefit from, and therefore those utilities have economic "need" for, contracts with QFs that have been approved by the appropriate ratemaking authority as offering electricity at or below the utility's avoided cost. Similarly, the Siting Council finds that a power sales agreement between a QF and a Massachusetts utility that results from a QF solicitation approved by the MDPU pursuant to its PURPA regulations, 220 CMR 8.00 et seq., constitutes evidence of the purchasing utility's need for power for economic efficiency and reliability purposes.

Accordingly, based upon the signed and approved contracts between NEA and three Massachusetts utilities for a total of 150 MW, and the evidence that NEA has successfully bid an additional 80 MW to Boston Edison pursuant to the MDPU's PURPA regulations, the Siting Council finds that the Massachusetts ratepayers of Boston Edison, Comm Electric, and Montaup are likely to capture economic-efficiency and reliability benefits specifically from the power resources associated with the NEA project.

Finally, the Siting Council considers NEA's third rationale -- that the long-range forecasts of demand and supply of Boston Edison, Comm Electric, and Montaup show that these three companies need to add new power resources for reliability purposes. In previous cases where a specific utility company has proposed to construct an energy facility to meet its own reliability or efficiency objectives, the Siting Council has relied upon such company-specific demand forecasts and supply plans to determine need. Cambridge Electric Light Company, 15 DOMSC 187 (1987); Hingham Municipal Lighting Plant, 14 DOMSC 7 (1986); Boston Edison Company, 13 DOMSC 63 (1985).

In the instant case, however, a non-utility company has proposed a facility to satisfy the economic and reliability objectives of utilities in New England and certain ones in Massachusetts. Here, the Siting Council has determined that it is not appropriate to adjudicate the issue of whether the purchasing utilities' forecasts of demand and supply support a finding that those companies need additional power resources for reliability or economic efficiency purposes. As a matter of policy, such determinations are more appropriately made in the context of Siting Council reviews of utility long-range forecasts and in MDPU reviews of utility RFPs and contracts for QF power.

Based upon the foregoing, the Siting Council finds that NEA has established (1) that consistent with the current resource use and development policies of the Commonwealth, ratepayers in Massachusetts generally benefit from the addition of QF power resources to their utilities' supply mixes, and (2) that specifically the ratepayers of Boston Edison, Comm Electric, and Montaup are likely to receive economic-efficiency and reliability benefits from the proposed additional power resources.

Accordingly, the Siting Council finds that NEA has established that Massachusetts is likely to receive reliability and economic benefits from the additional power resources proposed for 1990.

5. Conclusion on Need

NEA has established (1) that New England needs at least 300 MW of additional power resources for reliablity purposes by 1990, and (2) that the Commonwealth is likely to receive reliability and economic benefits from the proposed additional power within the same time period.

Accordingly, the Siting Council finds that the proposed 300 MW of additional power resources are needed by 1990.

B. Cost and Environmental Impact Analysis

1. Standard of Review

G.L. c. 164, sec. 69H requires the Siting Council to evaluate proposals to construct energy facilities in terms of their consistency with providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at lowest possible cost.

In implementing this statutory mandate in previous reviews of utility company facility proposals, the Siting Council has required that the petitioner show that its proposed project is superior to alternatives in terms of cost and environmental impact for meeting an identified need to add power resources for either reliability or economic purposes.[11] Cambridge Electric Light Company, 15 DOMSC 187, 214-218 (1986); Massachusetts Electric Company, 13 DOMSC 119, 178 (1985); Boston Edison Company, 13 DOMSC 63, 67-68, 73-74 (1985); Boston Gas Company, 11 DOMSC 159, 168 (1984).

In Massachusetts Electric Company, 13 DOMSC 119, 178-179 (1985), the Siting Council specifically found that the proposed Hydro-Quebec transmission line project was superior in terms of cost and environmental impacts to the alternatives considered by the company; however, the Siting Council also found that the company had failed to adequately evaluate a reasonable range of alternatives since it had failed to include demand management alternatives among the options considered. Ultimately, the Siting Council found that because New England's need for low-cost energy and additional capacity exceeded the quantity to be provided by the proposed Hydro Quebec project, the project was an acceptable solution to the region's power needs even though the company had not compared it to a full range of alternatives (id., p. 179).[12]

In the instant case, NEA submits that the Siting Council should modify its standards for determining whether a proposed QF project is superior to alternatives in terms of cost and environmental impact (NEA Brief, pp. 6-12). NEA argues that the Siting Council's project cost standard as articulated in the Hydro Quebec case is too stringent

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11/For the purposes of this discussion, the Siting Council will refer to this as the "project cost standard," even though this standard reflects a balancing test for minimizing cost and environmental impacts while ensuring needed energy supplies.

12/Subsequent to the Siting Council's decision in Massachusetts Electric Company, 13 DOMSC 119 (1985), the Massachusetts legislature amended the Siting Council's statute in 1986 to require the Siting Council to approve a company's long-range forecast only if the company has demonstrated that its forecast includes "an adequate consideration of conservation and load management." G.L. c. 164, sec. 69J.

for a QF facility proposal.[13] NEA proposes instead that the Siting Council apply (id., p. 10):

> a least-cost review that looks only at the avoided cost standard. So long as the cost of a project was less than the utilities' avoided cost, the project would be considered least cost. There would be no requirement to present a cost comparison among different QF alternatives .... Avoided cost would be the standard and the sole requirement would be that revenues over the life of the contract would be equal to or less than the avoided cost on a present value basis .... [Also] the QF project must show that it is sufficiently reliable, a showing which would involve a demonstration that the project is likely to be financiable. This is a greater concern for a QF project than for a utility.

Thus, NEA argues that a QF project is least cost if the petitioner has shown (1) that the cost of the proposed project is likely to be less than the utility's avoided cost, and (2) that the project can be financed.

The Siting Council recognizes that the historical development and application of its project cost standard has been shaped by the fact that all facility proposals previously considered have been submitted by utility companies. While the Siting Council agrees that some modification of the project cost standard may be necessary when applied to a QF project, the Siting Council must reject NEA's proposed two-part test.

The Siting Council recognizes that pursuant to 220 CMR 8.00 et seq., the MDPU makes determinations as to whether proposed QF contracts offer energy and power to utilities at or below their avoided costs. Such a determination, either made directly by the MDPU

13/As discussed in Section II.A.1.b., supra, NEA also suggested a modification of the Siting Council's need standard as applied in previous reviews of utility company facility proposals. NEA's rationales for the Siting Council adopting less stringent standards for reviewing QF facility proposals also are set forth in Section II.A.1.b., supra.

and endorsed by the Siting Council, or made by the Siting Council on its own, is a necessary but not sufficient finding to ensure that a QF project is consistent with the Siting Council's statutory responsibility to ensure an adequate supply of energy at minimum environmental impact and lowest possible cost.

G.L. c. 164, sec. 69H charges the the Siting Council with the unique responsibility of balancing environmental impact and cost considerations in determining whether to approve energy facilities proposed for construction in the Commonwealth. Because such a balancing test may not be accommodated in a standard that only compares a QF project's costs with the purchasing utility's avoided costs, the Siting Council must apply an additional standard that considers the environmental impacts of a proposed project. This "balancing test" is appropriate even for QF projects, given the Siting Council's unique role in the statutory scheme in reviewing proposals to site energy facilities and in ensuring that approved facility proposals minimize environmental impacts and costs. For these reasons, the proponent of a jurisdictional facility, including a QF facility, must demonstrate that its proposed facility is superior to alternatives in terms of cost and environmental impacts in meeting the identified need for additional power resources.

In recognizing its responsibility to conduct a balancing test in reviewing QF projects and utility company facility proposals, the Siting Council notes that it retains considerable discretion in striking a balance between minimizing costs and environmental impacts.

Further, the Siting Council agrees that as part of its balancing test, a QF facility developer must show that its proposed facility is financially viable. NEA asserts that this "financial viability standard" is necessary to ensure that the proposed QF project will actually go into service as planned (NEA Brief, p. 23). Indeed, in determining whether to approve the siting of a proposed QF facility in the Commonwealth, the petitioner must demonstrate that the project is likely to operate and produce energy over time. In other words, the petitioner must demonstrate that the development of the Commonwealth's resources that will occur through construction of the project will result in needed energy benefits. In so doing, the Siting Council goes beyond concerns for minimizing ratepayer risk -- which is the subject of the avoided cost standard -- and seeks to ensure that actual energy-production benefits will flow from the project that outweigh any adverse environmental impacts associated with siting and operating the facility.

In a case where a non-utility developer proposes to construct a QF facility in Massachusetts, the Siting Council determines whether the project (1) is superior to a reasonable range of practical alternatives in terms of cost, (2) offers power at a cost below the purchasing utility's avoided cost, (3) is superior to alternatives in terms of environmental impacts, and (4) is likely to be viable as a source of energy over time and will therefore satisfy the previously identified need for additional power resources. Finally, the QF developer must demonstrate that on balance the proposed project is consistent with ensuring needed energy supplies with a minimum impact on the environment at lowest possible cost.

2. Project Description

The NEA project consists of a dual-fuel, combined cycle cogeneration facility with a capacity of 300 MW. Natural gas is proposed as the primary fuel. The generating facility would require a new transmission line to connect the power plant to the region's bulk power transmission system, a gas pipeline to connect the power plant to the interstate gas pipeline that will deliver natural gas to the site, and on-site oil storage facilities to hold oil as a back-up fuel for the power plant (Exh. HO-1, pp. I-1 to I-3; Exhs. HO-26, HO-14A).

According to NEA, a "combined-cycle facility is an efficient generating facility which utilizes waste heat from the main combustion turbine to generate steam to drive turbines to generate additional electricity without the use of additional fuel" (Exh. HO-1, p. III-1). NEA has signed a letter of intent for its proposed generating facility to be designed, built, and operated by a joint venture of Westinghouse Electric Company ("Westinghouse") and Dravo Engineering

Company, Inc. ("Dravo"), under contract with NEA (Exh. HO-26); such a vendor was selected pursuant to a competitive bidding process (Tr. I, pp. 85, 88; Tr. II, pp. 7, 12-14, 22). This "turnkey," "design/build/O&M" contract contains incentives for keeping the project's construction on schedule and for maintaining the plant's operating performance at or above certain availability levels (Exhs. HO-26, HO-B-9.D(35)).

The NEA project has a capital cost of $135 million and a total project cost of $200 million, including costs of financing, professional services, and contingencies (Exh. HO-26; Tr. II, p. 13).

Of NEA's 300 MW output, 150 MW is currently under long-term power sales agreements approved or accepted by regulatory agencies: 100 MW to Boston Edison (Exh. HO-4), approved in 1986 by the MDPU in DPU 86-91 and DPU 86-91A; 25 MW to Comm Electric (Exh. HO-6), approved in 1987 by the MDPU (Exhs. HO-17, HO-B-18); and 25 MW to Montaup (Exh. HO-5), accepted by FERC (Exh. HO-B-17). All of these contracts begin with the commencement of plant operation, now expected on January 1, 1990 (id.; Exh. HO-B-7); the contracts with Boston Edison and Comm Electric run for 25 years, while the contract with Montaup has a term of 30 years. Under these existing contracts, NEA will sell power to each utility at less than its actual avoided cost, with provisions for floor prices for an initial period, front-end loading of payments, security arrangements, energy banking, and capacity payments (Exhs. H0-4, HO-5, HO-6). The Comm Electric contract also includes an incentive payment when the plant operates at a capacity factor higher than 85 percent (Exhs. HO-6, HO-CAT-8.A).

NEA has submitted a bid to sell an additional 80 MW to Boston Edison in response to its RFP for QF power (Exhs. HO-B-9.G, HO-B-9.C). NEA was the low bidder in terms of price and other criteria, and has been named as part of Boston Edison's "Award Group" (Exh. HO-B-9.E; Tr. II, pp. 9, 11). NEA states that it is negotiating a contract with Boston Edison for this 80-MW purchase (Tr. II, p. 9).

NEA's witness, Mr. Peter Roy, testified that under the terms of the existing agreements, NEA is obliged to offer an additional 20 MW to both Comm Electric and Montaup under the exact terms bid to Boston

Edison (Tr. II, pp. 10-11, 68-69). NEA has made such offers and is currently negotiating a second contract with Comm Electric (Tr. II, p. 42). According to Mr. Roy, NEA was informed by Montaup that it wanted NEA to bid the offered 20 MW in response to an upcoming solicitation for QF power (Tr. II, pp. 11, 43, 73). NEA states that Montaup expects NEA to fare well in such a competitive bidding process and to eventually sign a second agreement for the additional 20 MW (id.).

Financing for the project is being arranged by First Boston Corporation of New York ("First Boston") through a long-term project financing (Exhs. HO-B-9.A, HO-B-9.D(14); Tr. II, pp. 123-124; Tr. VI, p. 8). According to Peter Roy of NEA and Dorsey Lynch of First Boston, the project can be financed on the basis of an expected 250 MW under contract with Boston Edison, Comm Electric, and Montaup, even though all power sales agreements are not finalized (Tr. II, p. 44; Tr. VI, pp. 8-9).

NEA proposes that electric power generated at the facility will be delivered to the purchasing utilities via a new electric interconnection with the existing "Card Street" 345 kV transmission line (Exh. HO-1A). NEA states that because the Card Street line is jointly owned by the utilities purchasing NEA's power, NEA will avoid wheeling charges (Exh. HO-TF-1; Tr. II, pp. 75-76, 80, 86).

Also, NEA submitted drafts of two transmission-system studies prepared by NEPOOL's Medway Area Generation Study Group:[14] (1) a steady-state analysis that showed that "generation by Northeast Energy Associates in Bellingham, MA is beneficial to the New England transmission system," and "it would significantly reduce the power flows on the stressed facilities," and (2) a short-circuit study that

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14/The Medway Area Generation Study Group includes representatives of Boston Edison, Comm Electric, Eastern Utilities Associates, New England Power Service Company, and Northeast Utilities (Exhs. HO-19, HO-TF-2). The steady-state and short-circuit studies that are described in this group's draft "Evaluation of the Interconnection of Northeast Energy Associates/Ocean State Power Facilities," assume that the NEA project will be connected to the Card Street transmission line (Exhs. HO-19, HO-B-9.A).

concluded that installation of the NEA facilities will not create any short circuit problems in the surrounding area (Exh. HO-19).

In order to qualify as a QF under FERC regulations, NEA must sell five percent or more of the total thermal output of the plant to one or more steam purchasers located on or near the site[15] (Exh. HO-B-14.C).

NEA proposes to burn natural gas as the primary fuel for the generating facility. The facility, however, will be designed and constructed as a dual-fuel facility, so that it can also burn Number 2 fuel oil as well as natural gas (Exhs. HO-B-11, HO-13). NEA states that it intends to burn oil on no more than 30 days per year, but notes that it is nonetheless obtaining financing arrangements and environmental permits so that it can burn natural gas or oil on any given day (id.; Exh. HO-CFO-3; Tr. II, pp. 53-55, 96, 101-102).

NEA's fuel-acquisition strategy has been developed in conjunction with First Boston (Exh. HO-B-9.D(17); Tr. II, pp. 87-90). NEA states that it will attempt to purchase its own gas reserves or obtain long-term, economical supply contracts directly with a number of gas producers (id.). NEA has not yet finalized its choice of gas supplies (Tr. II, pp. 16-20, 95). NEA has a letter of commitment from ProGas of Canada to arrange for long-term gas supplies as a fall-back gas supply for the project in case more favorable arrangements cannot be obtained (Exh. HO-21; Tr. II, pp. 16, 90-91). Secondly, NEA states that it expects to arrange year-round, firm gas transportation with Algonquin Gas Transmission Company ("Algonquin") (Exh. HO-B-10.B; Tr. II, p. 94). Further, NEA asserts that if there are delays in constructing the additional interstate pipeline capacity needed for

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15/At present, NEA plans to sell steam to at least three customers: a cold storage company, for use in an ammonia absorption refrigeration unit; a carbon dioxide production plant for food processing; and a machinery company, for use in steam cleaning and in space heating. NEA states that there is additional steam available for sale to other industrial steam customers. (Exhs. HO-CFO-2, HO-14A, HO-B-9.D(31), HO-B-9.D(32), HO-27; Tr. II, pp. 73-74, 195-196, 198-200.)

firm transportation on the Algonquin system in order to deliver NEA's gas volumes to the site on a firm, 365-day basis, NEA will burn oil on the days when its gas supply is interrupted (Tr. II, pp 53-55).

In November 1987, NEA signed a 25-year, "oil/gas swapping" arrangement with Bay State to exchange NEA's gas for Bay State's oil (Exhs. HO-B-12A, HO-CFO-3; Tr. II, pp. 99-108). Bay State's witness, Charles Ellis, testified that Bay State will deliver oil to NEA's storage facility; then, as long as gas is flowing to NEA, Bay State may call upon NEA to release its natural gas supply to Bay State for its use (Tr. II, pp. 152-169; Exhs. HO-B-12, HO-B-12A). When Bay State uses NEA's gas, NEA will burn oil (Tr. II, pp. 101-102). According to Peter Roy of NEA, Bay State's ability to call upon NEA's gas would be limited each year to 30 days falling between December 21 and February 28 (Tr. II, pp. 99-101; Exhs. HO-B-12A, HO-CFO-3). Mr. Ellis further testified that Bay State expects to call upon NEA's gas as a peaking gas supply minimally in the early 1990s, and to increase its reliance upon NEA gas by the late 1990s as Bay State's system load growth warrants use of the additional resource over time (Tr. II, pp. 152, 162, 165-169, 173-175, 179-185; Exh. HO-CFO-3).

3. Cost Analysis

The Siting Council evaluates the NEA project in terms of whether it minimizes costs, by determining whether the proposed project (1) is superior to a reasonable range of practical alternatives in terms of cost, and (2) offers power at a cost below the purchasing utility's avoided cost.

a. Comparison of Alternatives

i. NEA's Analysis of Alternatives

NEA asserts that when compared to other means of generating electricity, a gas-fired, combined-cycle facility is the least cost option for meeting the identified need for additional power resources

(Tr. I, pp. 93-94).

In support of this contention, NEA presented the results of a quantitative analysis that compared the cost of constructing and operating a generic gas-fired, combined-cycle generating plant with the costs associated with other generating technologies (Exh. HO-1, secs. V, VI).

NEA's cost study compared twelve different electric generating options using a levelized-cost methodology that took into account the capital, fuel, and operating and maintenance ("O&M") costs attributable to each technology and fuel option (Exh. HO-1, Section VI; Tr. III, pp. 19-26). NEA asserts that this levelized cost analysis is an accepted approach for comparing investments in different technologies that have different cost streams and useful lives (Exh. HO-1, p. V-2; Tr. III, pp. 19-21, 72).

NEA's study relied upon industry data for capital costs, O&M costs, heat rates, and plant availability factors; upon Data Resources Inc.'s winter 1987 fuel price projection; and upon First Boston's financial assumptions (Exhs. HO-CAT-2.D, HO-CAT-2.E, HO-CAT-2.F, HO-7, HO-15; Exh. HO-1, pp. V-3 to V-6; Tr. II, pp. 18-42). NEA discussed the economic attributes of each option and then developed and compared the busbar costs[16] of the twelve generating options[17] (Exh. HO-1, pp. VI-12 to VI-33).

After eliminating eight of these options due to their relatively

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16/"Busbar" costs reflect the capital, fuel and O&M costs associated with power production, and do not incorporate transmission or distribution costs.

17/These options were: (1) a gas-fired combined-cycle unit; (2) a distillate-oil-fired combined-cycle unit; (3) a residual-oil-fired combined-cycle unit; (4) a baseload conventional coal unit; (5) a cycling conventional coal unit; (6) an atmospheric fluidized bed unit; (7) a pressurized fluidized bed unit; (8) an integrated gasification combined-cycle unit; (9) a residual-oil-fired steam plant; (10) a gas-fired combustion turbine plant; (11) a wood-fired steam plant; and (12) a municipal solid waste steam plant (Exh. HO-1, p. VI-14).

high costs, immature development status, or fuel-supply constraints, NEA subjected the remaining four generating options (gas-fired combined cycle, baseload conventional coal, atmospheric fluidized bed, and residual oil-fired steam) to further evaluation (id., p. VI-33). In this more detailed analysis, NEA analyzed the sensitivity of these technologies' busbar costs to different combinations of assumptions regarding fuel price projections, oil/gas mixes, discount rates, capital costs, and plant availability (id., pp. VI-31 to VI-39).

NEA asserts that the results of this generic screening analysis showed that "the gas-fired combined cycle unit remained the least cost technology under a variety of sensitivity analyses" (NEA Brief, p. 20).

NEA also analyzed projected levelized busbar costs associated with its actual proposed project (Exhs. NEA-1, NEA-2B). These cost estimates reflect expected capacity and O&M costs as they appear in NEA's design/build/O&M contract with Westinghouse/Dravo, and fuel costs associated with the fall-back ProGas contract (Exhs. NEA-1, NEA-2B; Tr. III, pp. 9-10). This analysis indicates that NEA's project will have (1) a capital cost of $666 per kilowatt (in 1990 dollars), (2) O&M costs of $17 per kilowatt per year starting in 1990, and (3) levelized natural gas prices of 4.82 cents per kilowatthour (in 1990 dollars) (Exh. HO-20; Tr. II, pp. 14-15, 17-18; Tr. III, pp. 12-13). Based upon these expected costs, the NEA project would have a levelized busbar cost of 6.71 cents per kwh, as compared to the 8.53 cents per kwh for a generic gas-fired combined-cycle unit that NEA had concluded was the lowest-cost of the technological options it analyzed (Exhs. NEA-1, NEA-2B, and HO-1, p. VI-32). With these results, NEA asserts that the proposed dual-fuel combined-cycle cogeneration facility with use of natural gas as the primary fuel is economically superior to other generating alternatives (Tr. III, pp. 13-14).

Further, NEA asserts that its proposed project is consistent with state energy policies favoring fuel diversification, greater competition in energy markets, expansion of generating capacity in small increments, and increased energy efficiencies through cogeneration (Exh. HO-1, pp. I-3 to I-6, III-19 to III-21, III-25, III-28; Exh. HO-CAT-2.A; Tr. I, pp. 44-47, 57, 61-64).

Finally, NEA contends that its cost analysis does not need to compare the proposed project or other generating technology to the costs of reducing energy requirements through electricity conservation and load management (Exh. HO-1, pp. VI-39 to VI-41). NEA asserts that it has provided forecasts of demand and supply for New England which incorporate reasonable estimates of conservation and load management (id., p. VI-40). NEA instead asserts that its project is not an alternative to cost effective conservation and load management, but a "necessary complement to meet future electric needs" (id., p. VI-41).

ii. Evaluation of NEA's Analysis of Alternatives

NEA has presented extensive documentation in support of its assertion that a gas-fired, combined-cycle cogeneration facility is superior to other technologies in terms of cost. The Siting Council notes that NEA's analysis has adequately (1) evaluated a reasonable range of generating options; (2) analyzed the specific costs of the NEA project and compared them to the costs of other technologies; and (3) placed the proposed project within the context of the Commonwealth's stated policies regarding utility supplies that encourage competition among alternative sources of supply, reduction of the state's oil dependency, increased reliance upon natural gas as a fuel source for electricity generation, and greater efficiency in energy production through increased cogeneration.

The Siting Council, however, notes a number of deficiencies in NEA's economic analysis. First, this cost analysis places no economic value on the thermal (i.e., steam) output of the cogeneration facility (Tr. III, p. 33), and as such, tends to underestimate the cost advantages of a cogeneration facility relative to other non-cogeneration electric-generating technologies.

Second, in its economic analysis NEA compares the levelized costs of all twelve generating options assuming a common 1989 start date (Tr. III, pp. 38-39; Exh. HO-1, p. VI-30). Among these twelve options are technologies with long lead times (e.g., a construction period of four or five years, and a design period of four years), even though the analysis (conducted in 1987) compares options as if they could all be available to meet capacity needed starting in 1989 or 1990 (id.; Tr. III, pp. 16-17; Tr. II, pp. 26-27). This approach probably understates the capital costs of such long-lead-time options relative to a combined cycle, which has a two-year construction period. More importantly, the approach unrealistically portrays plausible options open to a developer for determining which generating facility options may be placed in service by the time capacity is needed.

Third, NEA[18] and Bay State[19] presented little evidence regarding specific quantitative economic benefits or costs associated with the oil/gas swapping arrangement. Such an omission is not critical to demonstrating the economics of a project that is otherwise cost-justified, but this omission does understate the economic value

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18/Peter Roy of NEA testified that NEA will receive a small economic benefit from the oil/gas swapping arrangement in the form of an annual demand charge of $180,000 to be paid by Bay State (Tr. II, pp. 103-104, 135; Exhs. HO-B-12A). Mr. Roy stated that this financial benefit to NEA does not represent "a significant amount of money," compared to the more important benefit to NEA of having a cooperative relationship with Bay State instead of a relationship as adversaries over the "bypass" issue (Tr. II, pp. 103-105).

19/The Siting Council notes that Mr. Ellis, Bay State's witness, testified that the oil/gas swapping arrangement is valuable to Bay State's customers whenever the costs of the oil that Bay State would obtain for NEA in exchange for NEA gas are less than what it would cost Bay State to obtain gas supplies through other sources (Tr. II, pp. 168-169). Also, Mr. Ellis stated that the arrangement should be viewed as an alternative to Bay State having to construct other facilities (Tr. II, p. 153), and as a peaking supply for which Bay State pays no capital costs (id., p. 154). However, Mr. Ellis offered no quantitative estimate of the expected value of this arrangement to Bay State or the Commonwealth (id., pp. 169-171, 187-191).

of the project to the Commonwealth.

Finally, NEA's analysis does not reflect savings associated with the NEPOOL study's conclusion that the project is beneficial to the New England transmission system.

In short, NEA's cost analysis fails to consider certain "economic externalities" that might enhance the cost advantages of the generating option actually proposed by NEA when compared to other technologies. However, absent a quantitative analysis of these economic considerations, the Siting Council can only make a general finding that such externalities would have a positive economic advantage for the project relative to alternatives.

Still, the Siting Council finds that NEA has presented an adequate analysis which compares the costs of the proposed project to a reasonable range of alternatives and concludes that the project minimizes costs compared to those alternatives.[20] Accordingly, the Siting Council finds that a gas-fired, combined-cycle cogeneration technology is superior to alternatives in terms of cost.

b. Comparison of the Project with Utilities' Avoided Costs

NEA provided the contracts it signed with Boston Edison, Comm Electric, and Montaup for a total of 150 MW of the project's 300 MW output (Exhs. HO-4, HO-5, HO-6). Each of these contracts includes provisions that tie the price that the utility will pay to NEA to the utility's actual avoided cost (Exh. HO-1, pp. VII-1 to VII-9). NEA

20/ In making this finding, the Siting Council notes that the appropriate procedural mechanisms for comparing the costs of generating electricity to the costs of reducing demand through conservation and load management are within the context of (1) Siting Council reviews of utility companies' long-range forecasts of supply and demand, (2) Siting Council evaluations of utility companies' proposals to construct energy facilities, and (3) MDPU evaluations of utility companies' long-range avoided cost calculations, for use in approving QF contracts or in setting the ceiling prices in utility companies' RFPs for QF power, as provided in 220 CMR 8.00 et seq.

also submitted an analysis of the net present value of the expected stream of payments to NEA under each contract, and compared it to the net present value of each utility's projected avoided cost (id., pp. VII-3, VII-7, VII-9). NEA asserts that its analysis shows that, for each agreement, the sum of the net present value of the projected payments to NEA over the life of the contract is less than the net present value of the utility's avoided cost (Exh. HO-18).

NEA also cited the MDPU's order in DPU 86-91-S, where the MDPU approved Boston Edison's 100 MW contract with NEA and noted that the contract is likely to yield benefits to ratepayers even in the event that fuel prices fall to the lower range of predicted prices (Exh. HO-1, p. VII-4). NEA also presented testimony and documentation showing that the MDPU has approved Comm Electric's contract with NEA (Exhs. HO-17, HO-B-18) and that FERC has accepted the Montaup contract with NEA (Exh. HO-B-17).

Further, NEA submitted documentation showing that (1) NEA successfully offered 80 MW to Boston Edison pursuant to a MDPU-approved QF bidding process, and (2) the price terms that NEA submitted in its bid to Boston Edison offer savings to that utility's ratepayers over the life of the contract when compared to Boston Edison's published avoided costs (Exhs. HO-B-9.E, HO-B-9.D(40)). NEA asserts that the price terms in its bid to Boston Edison are identical to those offered to Comm Electric and those that NEA will submit in its bid Montaup in response to its solicitation for QF power (Tr. II, pp. 41-44).

Finally, NEA presented an analysis which summed the revenues NEA expects to receive from the contracts it has signed and expects to sign with Boston Edison, Comm Electric, and Montaup (Exhs. HO-18, HO-CAT-8.A, HO-CAT-9; Tr. III, pp. 73-86). This analysis also compares these estimated revenues with the three utilities' avoided costs. The results of the analysis show that the net present value of the three utilities' payments to NEA is $1,055 million as compared to the net present value of the utilities' combined avoided costs of $1,314 million (Exh. HO-18). Thus, this analysis indicates that NEA's existing and proposed contracts represent a $259-million savings to the ratepayers of Boston Edison, Comm Electric, and Montaup over the life of the contracts (id.).

Based upon the foregoing, the Siting Council finds that NEA has adequately demonstrated that the NEA project is likely to provide substantial savings to the ratepayers of Boston Edison, Comm Electric, and Montaup. Accordingly, the Siting Council finds that the proposed project offers power at a cost below each purchasing utility's avoided costs.

c. Conclusion

The Siting Council finds that the NEA has demonstrated that (1) its proposed project is superior to a reasonable range of alternatives on the basis of cost, and (2) its project offers power at a cost below each purchasing utility's avoided costs.

Accordingly, the Siting Council finds that NEA has demonstrated that its proposed project minimizes cost.

4. Environmental Analysis

The Siting Council evaluates the proposed project in terms of whether it is superior to alternatives in terms of environmental impacts.

NEA presented an environmental assessment of other fuels and generating technologies which it asserts could be used to produce steam and power (Exh. HO-1, pp. VI-1 to VI-31).

NEA's analysis compared natural gas to petroleum fuels, coal, and biomass, in terms of their cost escalation risk, security of supply, transportation and infrastructure requirements, siting and land-use requirements, and other environmental impacts (e.g., air quality, solid waste) (id., pp. VI-1 to VI-12; Tr. III, pp. 49-52). According to NEA's analysis, natural gas is the preferred fuel in terms of minimizing overall environmental impacts (Exh. HO-1, p. VI-12).

NEA evaluated eight different generating technologies in terms of their environmental impacts, siting and land-use requirements, lead time and capital cost risks, plant availability, and technological maturity (id., pp. VI-1, VI-12 to VI-28, VI-30). Based upon its assessment of power generation technologies and fuel options,[21] as described in Section II.B.3.a.i, supra, NEA concluded that for a project of the size proposed by NEA, combined-cycle plants are preferable to alternatives (Exh. HO-1, p. VI-15). NEA asserts that the relative advantages of combined-cycle plants are (1) efficiency in terms of electricity generated per unit of fuel input; (2) high availability factors, averaging in the range of 90 percent; (3) minimal sulfur dioxide emissions, minimal solid waste disposal problems, and smaller land requirements; (4) low capital costs and short construction lead times; (5) status as a proven technology (id., pp. VI-12 to VI-31).

NEA states that its ranking of fuel and technological options in terms of their environmental attributes enabled NEA to screen out options not likely to be environmentally or technologically feasible (id., pp. VI-1, VI-29 to VI-31, VI-33). Then NEA subjected the most promising technologies in terms of minimizing environmental impacts to further economic review (see Section II.B.3.a.i, supra).

NEA's environmental assessment of different fuels and generating technologies concludes that a gas-fired combined-cycle power plant produces electricity efficiently and reliably with lower environmental impacts and shorter lead times as compared to other generating options (Exh. HO-1, pp. VI-12 to VI-15, VI-29 to VI-31).

The Siting Council notes certain weaknesses in NEA's environmental assessment of different fuels and technologies. First, the analysis failed to attribute environmental advantages to a cogeneration technology, as compared to other forms of electricity generation (Tr. III, pp. 33, 68-70). In fact, this omission may understate certain environmental advantages associated with the greater energy efficiencies of a cogeneration facility when compared

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21/See footnote 17, supra, for a listing of the technology/fuel options evaluated by NEA.

to a non-cogeneration electric-generating technology.

Second, NEA provided minimal data to describe and analyze environmental impacts (Tr. III, pp. 57-61; Tr. IV, p. 19; Exh. HO-1, pp. VI-1 to VI-31, Notes). Instead, NEA's environmental assessment was developed judgmentally to derive quantitative rankings for the alternatives (Tr. III, pp. 18-19; Exh. HO-1, pp. VI-1 to VI-31). Further, NEA relied almost exclusively on opinion rather than being grounded in source documents on the environmental impacts of generation alternatives.

The Siting Council acknowledges that in the absence of recognized common units of measurement or methods of quantitative analysis, a considerable application of expert judgment is necessary when comparing the environmental attributes of fuel and technological options. However, in this case, NEA's environmental analysis is grounded almost exclusively in the expertise of the witnesses who prepared the assessment for NEA. NEA failed to provide references to source documents or data relied upon by the analysts in preparing the assessment; as such, the Siting Council is deprived to a large degree of the opportunity to reach independently the same conclusion as NEA's consultants -- that a gas-fired, combined-cycle cogeneration plant is preferable to other forms of electric generation in terms of environmental impacts.

Still, NEA has provided the Siting Council with a detailed and comprehensive description of each fuel and technological option that it considered. This description enables the Siting Council to evaluate NEA's assessment system and NEA's application of its review criteria to individual fuel and technology options. As such, in spite of the problems identified above, NEA's method is at least minimally reviewable. In that NEA has presented a detailed, reviewable and systematic qualitative assessment of the environmental attributes of alternatives, the Siting Council finds that NEA's environmental assessment of project alternatives is acceptable as a basis for making findings on whether the proposed project is superior to alternatives on the basis of environmental impacts.[22]

The Siting Council finds that NEA has demonstrated that a gas-fired, combined cycle cogeneration facility is superior to alternatives in terms of environmental impacts.

5. Analysis of Project Viability

NEA states that it recognizes that the financial viability of a QF project is "one issue of special concern to the Council" (NEA Brief, p. 23). According to NEA (id., p. 23):

> for a QF the crucial factor is the financiability of the project. Once the project receives financing, the prospects for eventual operation become far more assured .... The best arbiters of the financial viability of a QF project are the financial institutions which will provide the capital necessary for the project. They have the most to lose if the investment does not come to fruition.

(See also Exh. HO-B-13.)

In support of this position, NEA's witness, Mr. Lynch of First Boston, stated that First Boston has committed to arranging a project financing of the NEA project (Tr. VI, p. 8; see also Tr. I, pp. 74-75; Exh. HO-B-9.D(14)). Mr. Lynch testified that First Boston extensively analyzed certain attributes of the project and concluded it is "an extremely sound and well-conceived project from a financial viewpoint" and can be financed (Tr. VI, p. 9).

NEA has asserted that (1) the existing and proposed power sales

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22/This case represents the first time the Siting Council has evaluated a QF facility proposal. While NEA has provided in this case a detailed qualitative description of the environmental impacts of different generating technologies and fuel options, the Siting Council notes that other possible methods of environmental assessment have not been investigated. In future cases, the Siting Council may require the applicant to demonstrate the environmental superiority of its proposed project through a better documented and possibly more quantitative method of assessment.

agreements for 270 MW of the plant's output are likely to generate sufficient revenues, even over a wide range of sensitivity analyses, to make the project economically viable (Tr. II, pp. 43-44, 51-52, 123-125, 129-130, 139; Tr. VI, pp. 9-11, 13-15); (2) the project's finances are most sensitive to fuel cost escalation but are still protected from excessive risk since, under the "worst case" scenario where NEA purchases relatively expensive natural gas supplies through ProGas, gas price changes are tied to changes in NEA's power-sales revenues (Tr. VI, pp. 19-20; Tr. II, pp. 91-92; Exh. HO-21); and (3) the plant will be designed, constructed and operated by an experienced contractor, whose 10-year operating contract with NEA has incentives and penalties to keep the plant's construction schedule on time and its operating performance above a target availability of 90 percent (Tr. I, pp. 97-98; Tr. II, pp. 15, 111-112; Tr. VI, pp. 9, 11; Exhs. HO-26, HO-B-9.D(35)).

NEA further asserted that First Boston has examined approximately 100 different sets of financial assumptions for the NEA project, and determined that the project could be financed under all scenarios (Tr. VI, p. 9; Tr. II, p. 139).

Mr. Lynch testified that First Boston will arrange project financing, subject to a decision of the Siting Council on the proposed facilities (Tr. VI, p. 14; Tr. I, p. 129; Tr. II, pp. 46-47, 52).

NEA also submitted two different versions of the project's pro forma balance sheet -- one which reflects "conservative" assumptions as of August 1987 (Tr. II, pp. 127-137; Exh. HO-B-9.D(15)), and another which reflects NEA's current cost, income, and operating assumptions, as of October 23, 1987 (Exh. HO-20; Tr. II, pp. 137-139; Tr. VI, pp. 20-23).

In addition, NEA provided documents outlining its fuel-supply objectives and gas-acquisition strategy (Exhs. HO-B-9.D(17), HO-B-10). To meet the objectives of gas transportation reliability, long-term supply dependability, supply diversity, and price stability, NEA developed a strategy of acquiring a portfolio of supplies, including ownership of producing and proven reserves of gas (Exh. HO-B-9.D(17)). NEA also submitted documentation relating to its negotiations with possible gas suppliers and transporters (Exhs. HO-B-9.D(21), HO-B-9.D(22), HO-B-9.D(23), HO-B-9.D(24), HO-B-9.D(25), and HO-B-10). Mr. Stephen Roy stated that NEA's financiers will close the project financing before NEA finalizes its firm, year-round, long-run gas supply and transportation arrangements (Tr. I, pp. 124-127).

NEA asserts that these exhibits and testimony show that "the economics of the NEA project are excellent ... [and] provide a high degree of confidence that the facility will be financed, constructed and put into service" (NEA Brief, p. 25).

Based upon the foregoing, the Siting Council finds that NEA has demonstrated that its proposed project is reasonably likely to be financed and constructed. Further, the Siting Council finds that the project is likely to be a viable source of energy over the life of NEA's contracts with Boston Edison, Comm Electric, and Montaup.

Accordingly, the Siting Council finds that NEA has established that the projected project is likely to be viable as a source of energy over time.

6. Conclusion: Weighing Cost and Environmental Impacts

The Siting Council has previously found that (1) a gas-fired, combined-cycle cogeneration project is superior to a reasonable range of alternatives in terms of costs, (2) NEA's project offers power at a cost below each purchasing utility's avoided costs, (3) a gas-fired, combined-cycle project is superior to other generating technologies in terms of environmental impacts, and (4) NEA's project is likely to be a viable source of energy. In sum, the Siting Council has determined that NEA's proposed project is economically and environmentally superior to alternatives, and is likely to produce needed electricity such that ratepayers' electricity costs are lower than what they would otherwise be in the absence of the project.

Accordingly, the Siting Council finds that NEA has demonstrated that its proposed project is consistent with ensuring a necessary energy supplies with minimum impact on the environment at lowest possible cost.

III. ANALYSIS OF THE PROPOSED FACILITIES

A. Standard of Review

Before approving an application to construct energy facilities, the Siting Council requires the petitioner to show that its proposed siting plans for the facility are superior to the proposed alternatives. Boston Edison Company, 13 DOMSC 63, 67-68, 76-77 (1985). A petitioner is required to demonstrate that its proposed facilities are sited at locations that minimize costs and environmental impacts.

In previous cases, once the Siting Council has determined that new facilities are needed and that the applicant has presented plans that satisfy the previously identified need and are superior to alternative plans in terms of cost and environmental impacts, the Siting Council has required utility-company petitioners to show (1) that they have examined a reasonable range of practical siting alternatives, and (2) that the proposed site for the facility is preferable to the alternative site(s) on the basis of a balancing of cost, environmental impact, and reliability of supply. Cambridge Electric Light Company, 15 DOMSC 187, 195-196, 229-237 (1987); Hingham Municipal Lighting Plant, 14 DOMSC 7, 22-32 (1986); Massachusetts Electric Company, 13 DOMSC 119, 183-184, 190-248 (1985); Boston Edison Company, 13 DOMSC 63, 67-68, 76-81 (1985).

NEA proposes that the Siting Council modify its standards for reviewing QF facility proposals (NEA Brief, pp. 6-11). NEA asserts that in reviewing the proposed Hydro-Quebec transmission facilities in Massachusetts Electric Company, 13 DOMSC 119 (1985), the Siting Council required the applicant to demonstrate that it had considered practical alternatives to the proposed facilities and that it had taken all reasonable steps to minimize the proposed facilities' impacts on the environment (id., pp. 6-7). NEA submits that these standards are not the most appropriate ones to use for reviewing QF projects since the standards may be unduly rigorous (id.).

In their place, NEA proposes that a QF should be required to show that (1) it has used reasonable criteria to choose a site and (2) the project will meet all applicable regulatory requirements. In support of its modified two-part standard, NEA argues that (id., pp. 10-11):

> A ... standard, like that of Hydro-Quebec would be a comparison of practical alternatives. However, there should be a recognition that what is practical for a QF developer is very different than what is practical for a utility. QF developers do not have existing rights of way nor do they have the power of eminent domain. Their ability to acquire a particular site is far more constrained than a utility. In addition, a developer simply does not possess the revenues to perform detailed engineering studies of a number of sites. We suggest that the developer must show that he has utilized reasonable criteria for site selection.
>
> Finally, we propose that QF projects be required only to demonstrate that the project will meet all applicable regulatory requirements. While the Council has the authority to require additional environmental mitigation measures, to do so could place projects larger than 100 MW at a competitive disadvantage. Should the Council exercise the option to mandate additional environmental measures, we urge that a policy be adopted that gives substantial consideration to the costs of any such modification.

The Siting Council agrees that the developers of QF projects have different options and constraints with respect to their ability to obtain certain sites for constructing energy facilities. This fact, however, does not affect the Siting Council's mandate to ensure that needed energy facilities are constructed at sites that minimize costs and environmental impacts. The Siting Council's regulations require any proponent of an energy facility to provide cost and environmental information regarding a proposed and alternative sites. 980 CMR 7.04(8)(e).

Therefore, the Siting Council notes that while all of its standards of review cannot be applied to utilities and QFs in an identical manner, the Siting Council's statute and regulations do not envision a more limited review or a reduced burden of proof for different types of applicants.

In sum, where any petitioner proposes to construct a jurisdictional facility in the Commonwealth, the Siting Council determines whether the petitioner has demonstrated (1) that it has considered a reasonable range of practical alternatives for siting the proposed facility, (2) that the proposed site is superior to alternatives in terms of cost, (3) that the proposed site is superior to alternatives in terms of environmental impacts, and (4) that the proposed site is superior to alternatives in terms of reliability. Finally, the Siting Council requires the petitioner to demonstrate that on balance the proposed site is preferable to the alternative site in terms of cost, environmental impacts, and reliability of supply.

B. Do the Proposed Facilities at the Proposed Site Meet the Need to Provide Energy Supplies with a Minimum Impact on the Environment at Lowest Possible Cost?

1. Description of the Proposed Facilities and Sites

The NEA proposed facilities include (1) a 300-MW, dual-fuel, combined-cycle cogeneration facility, and (2) ancillary facilities necessary to support fuel delivery and power transmission for the proposed generating facility.

NEA has petitioned to site its proposed facilities in the Town of Bellingham, Massachusetts, at a site known as the "Winiker Site" or at an alternate site known as the "Varney Site." The Winiker Site, which NEA considers its "primary" site, is a 44-acre undeveloped parcel of industrially zoned land (Exh. HO-1, p. I-1; Exh. HO-B-15). The Varney site is a 142-acre parcel of undeveloped, agriculturally zoned land (Exh. HO-1, p. I-1).

NEA's proposed generating facility consists of two gas turbines, two heat recovery steam generators, and one steam turbine (Exhs. HO-13, HO-26, HO-14A). According to NEA, the facility will have a 190-foot stack with emissions consistent with the "Best Available Control Technology" ("BACT") as determined by the Massachusetts Department of Environmental Quality Engineering ("MDEQE") (Tr. II, p.

120; Exh. HO-1, p. IV-3)).

The proposed ancillary facilities include (1) a 345 kV transmission line and related electrical facilities to connect the power plant to the existing Card Street 345 kV transmission line that runs near the proposed and alternate sites; (2) a gas pipeline to interconnect the power plant to an interstate gas pipeline (Exh. HO-13); and (3) oil storage tanks with a total volume of 2.0-2.5 million gallons to store oil on site as a back-up fuel for the power plant (Exh. HO-1, pp. I-1 to I-3; Exhs. HO-26, HO-CFO-3, HO-13, HO-14A; Tr. II, p. 161).

The precise length of the proposed electric transmission line and gas pipeline interconnections would depend upon whether the facility is constructed at the Winiker or Varney site. If the generating facility were constructed at the Winiker site, about 0.25 mile of transmission line would be constructed to interconnect with the Card Street line, which is not contiguous to the site (Exh.HO-26); the line would traverse property leased from a private owner by NEA (Exh. HO-B-9.D(4)). The gas pipeline interconnection for the Winiker site would be several hundred feet in length, as Algonquin's interstate pipeline crosses the Winiker site (Tr. V, p. 155). If the generating facility were constructed at the Varney site, the electric transmission interconnection would be a few hundred feet long, since the Card Street line is contiguous to the Varney property. At the Varney site, the gas pipeline interconnection would be about one mile in length to interconnect with Algonquin's pipeline (Tr. V, p. 156).

NEA provided exhibits to show that the bulk power transmission system in New England needs no reinforcement to accept and transmit the power from the NEA facility (Exh. HO-19).

At present, NEA is not proposing any oil pipeline facilities for the plant, since oil is currently proposed to be delivered to the site via trucks (Exh. HO-B-11; Tr. II, pp. 175).

The project is scheduled for a two-year construction period, with site preparation work starting in spring 1988 (Exh. HO-B-9.D(3)). Partial power associated with a single-cycle operation is expected in mid-1989 and full power associated with a complete combined-cycle facility scheduled for January 1, 1990 (Exh. HO-B-7; Tr. II, pp.

58-60). The work force during the operating phase is expected to be several dozen persons, assuming round-the-clock production (Exhs. HO-B-9.D(20), HO-B-9.D(30), Tr. II, p. 148-149).

2. Siting Alternatives: NEA's Site Selection Process

NEA submitted documents and testimony to describe the process and criteria NEA used to select a general location and then a specific primary and alternate site for the proposed facilities (Exh. HO-E-16; Tr. I, pp. 81-110).

NEA's witness, Stephen Roy, testified that since NEA sought to develop a dual-fuel, combined-cycle cogeneration project with natural gas as its primary fuel, the key criteria used to select a general location related to power sales, fuel supply, and power transmission considerations (Tr. I, pp. 81-89).

According to Stephen Roy, NEA first determined that utility companies in New England and Massachusetts needed power, which focused NEA's interest in developing a project in the southern New England region where NEA determined that market demand existed (Tr. I, pp. 81-82, 91-93; Exh. HO-E-16).

NEA asserted that the next critical siting criterion for its gas-fired project was the need to develop the QF project within close proximity to at least one and preferably more than one existing or proposed interstate gas pipeline (Exh. HO-E-16; Tr. I, pp. 88-89). NEA stated that this consideration was necessary in order to minimize the cost of constructing pipeline facilities needed to deliver gas to the plant's site, and to minimize gas supply and transportation costs by fostering competition among possible gas transporters with access to different groups of producers (Exh. HO-E-16; Tr. I, pp. 89, 101-102). This criterion led NEA to seek a location in or near the towns of Mendon, Massachusetts, Lincoln, Massachusetts, or Southington, Connecticut -- all three of which towns are located where the existing Algonquin pipeline and Tennessee Gas Pipeline Company ("Tennessee") pipeline systems intersect and near to where the proposed Champlain Pipeline Project may connect with the Algonquin and

Tennessee systems (Exh. HO-E-16).

NEA stated that its third general siting criterion revolved around the need to locate the project adjacent to an existing major transmission line so as to minimize the costs of delivering the project's power to the utility purchasers (id.; Tr. I, pp. 103-104). According to NEA, the three towns identified as prime locations on the basis of proximity to gas pipelines also have major electric transmission lines nearby (Exh. HO-E-16).

Next, NEA described its method for determining which of the three locations offered the best site from NEA's perspective. NEA asserted that it used the following criteria to identify acceptable and unacceptable locations: (1) NEA sought to receive deliveries of gas at a high enough pressure to avoid any need for secondary compression; (2) NEA sought to locate the facility next to a transmission line owned by one or more of the utility companies that was likely to contract to purchase NEA's power, so as to minimize or eliminate wheeling charges (id.; Tr. I, p. 108); and (3) NEA sought to locate in Massachusetts, since Massachusetts companies were contracting to purchase NEA's power and NEA believed that a Massachusetts location for the project would yield benefits to the Commonwealth in terms of tax revenues and job opportunities (Exhs. HO-E-16, HO-B-9.D(19), HO-B-9.D(20), HO-B-9.D(33)).

NEA stated that application of these criteria led NEA to reject Lincoln, Massachusetts and Southington, Connecticut, and to select the Mendon, Massachusetts area as the primary location for siting the project (Exh. HO-E-16).

Mr. Stephen Roy testified that, once NEA narrowed its target area, NEA sought to locate in a town that exhibited favorable community support for developing an energy project within its borders (Tr. I, pp. 105-110). NEA further asserted that it identified specific parcels of land as possible locations for its facility by looking for sites that met the following criteria: (1) availability of an industrially zoned parcel, or a parcel adjacent to industrially zoned areas; (2) proximity to potential steam users; (3) easy access to either the Algonquin or Tennessee pipeline facilities; (4) easy access to electric transmission lines; (5) proximity to existing rail lines; and (6) access to an adequate water supply (Exh. HO-E-16; Tr. I, p. 104).

NEA stated that it determined that the Winiker site located in Bellingham, Massachusetts, a town bordering Mendon, met these criteria, and the Varney site in Bellingham was an acceptable alternate site since it met all criteria other than industrial zoning (Exh. HO-E-16; Tr. I, p. 110). Mr. Stephen Roy testified that NEA's discussions with community officials and organizations in Bellingham, including the Town Administrator, the Bellingham Conservation Commission, the Box Pond Association, and the Charles River Watershed Association, indicated local support for the project and local preference for construction on the Winiker site (Tr. I, pp. 105-106, 119).

The Siting Council finds that the site-selection criteria used by NEA to identify general and specific locations for its proposed facilities are well suited for eliciting sites that minimize the economic costs and environmental impacts of constructing and operating needed energy facilities.

By applying its general and specific site-selection criteria, NEA effectively developed multiple siting options that served its objectives of negotiating economical fuel supply, power sales, and land-purchase agreements. In choosing criteria that minimize its own costs of construction and energy production, NEA has selected criteria that serve the Siting Council's dual interests of ensuring energy supplies at lowest cost and minimizing disruption of the Commonwealth's physical resources. In particular, NEA's criteria of seeking to locate its cogeneration facility near existing gas pipelines and electric transmission lines for cost-minimization reasons, coincides with the Siting Council's preference for locating needed energy facilities on or near existing as opposed to new rights of way. Massachusetts Electric Company, 13 DOMSC 119, 191-192 (1985); Boston Edison Company, 3 DOMSC 44, 54 (1978). These criteria favor the development of generating facilities at sites that minimize the environmental impacts and economic costs of a new power plant's interconnections with existing gas pipeline and electric transmission systems.

Based upon the foregoing, the Siting Council finds that NEA has developed and applied a reasonable set of criteria for identifying possible sites for its proposed facilities. Accordingly, the Siting Council finds that NEA has demonstrated that it has considered a reasonable range of practical alternatives for siting the proposed facilities.

3. Cost Analysis of the Proposed and Alternate Sites

NEA submitted information relating to any differences in direct development costs and in licensing and construction schedules that may result in siting the facilities at the proposed Winiker site versus the alternate Varney site (Exh. HO-12; Tr. I, pp. 111-112; Tr. V, p. 151). NEA identified seven variables that affect differences in cost and licensing/construction schedules between the two sites. These variables were (1) land ownership and costs; (2) rezoning issues; (3) environmental permitting issues; (4) gas pipeline interconnection costs; (5) steam pipeline costs; (6) electric transmission line interconnection costs; and (7) engineering/construction services (Exh. HO-12; Tr. I, pp. 113-118).

In regard to land costs, NEA asserted that use of the Winiker site would represent a savings to NEA of $4.7 million and up to six weeks of time. NEA noted that it has a written agreement with the owner of the Winiker site for $2.3 million whereas NEA has only an oral agreement with the owner of the Varney site for $7 million (Exhs. HO-12, HO-B-9.D(5); Tr. I, pp. 114, 120-121; Tr. V, p. 152).

With respect to zoning issues, NEA asserted that the Winiker site is already zoned for industrial uses, while the Varney site is currently an agricultural zone (Exhs. HO-12, and HO-1, p. I-1). NEA noted that the Varney site would have to be rezoned if NEA elected to construct its facilities there (Exh. HO-12). NEA estimated that a rezoning process could take up to 18 months and that the outcome of such a rezoning request is unknown (id.; Tr. V, pp. 163-164).

In regard to environmental permitting, NEA asserted that use of the Varney site could add as much as five weeks to the licensing schedule, since more detailed air-quality modelling and site planning has been performed for the Winiker site than for the Varney site (Exh. HO-12; Tr. V, pp. 154-155).

With respect to gas pipeline construction costs, NEA asserted that the costs at the Winiker site are approximately $1 million less than at the Varney site, since the Algonquin pipeline traverses the Winiker parcel and comes no closer than a mile to the Varney site. Further, NEA asserted that use of the Varney site would require NEA to obtain a new right of way for its gas pipeline connection. NEA stated that the time necessary to acquire such a new right of way is difficult to predict and could impact NEA's ability to close on its project financing with First Boston (Exh. HO-12).

With respect to steam pipeline costs, NEA estimated that it would cost $1 million more to site the cogeneration facility at the Varney site, since at least some of the steam purchasers are closer to the Winiker site (id.).

In regard to electric transmission interconnection costs, NEA asserted that these costs are higher if the Winiker site is used rather than the Varney site, since the Card Street transmission line is contiguous to the Varney site but not to the Winiker site (Tr. I, p. 115). NEA has leased the land connecting the Card Street right of way and the Winiker site for $5,000 a month and hopes to avoid these monthly rental costs by purchasing it for $1 million (Tr. V, pp. 137-140, 152-153). No such leasing or purchase costs would be necessary for use of the Varney site (Exh. HO-12).

With respect to engineering and construction services, NEA asserted that there would be additional but unspecfied engineering and construction cost and scheduling impacts associated with use of the Varney site, since NEA's engineering consultants' preliminary work and the Westinghouse/Dravo design/build contract price assumed construction would occur at the Winiker site (id.; Tr. V, pp. 160-161).

NEA's analysis concluded that construction of the proposed facilities at the Winiker site as opposed to the Varney parcel would have direct cost savings to NEA of approximately $5 million and would allow NEA's permitting, financing, and construction schedules to remain on target for a January 1990 commercial operation date (Exh. HO-12). NEA asserted that use of the Varney site would introduce delays in permitting, financing, and construction, resulting in a 9-to-18 month delay in the schedule (id.). NEA estimated that such scheduling delays could add indirect costs ranging from $1 million to $4 million per year over the life of the project, because delays in closing could result in increased interest rates for project financing, increased gas supply prices, and increased construction costs (id.; Tr. V, pp. 161-163). Yet NEA acknowledges that interest rates and gas prices could go up or down in future months (Tr. II, pp. 125-126, 145).

NEA concludes that siting the project at the Winiker location results in lower costs and no scheduling delays (NEA Brief, p. 37).

The Siting Council finds that NEA's estimates of direct cost differences associated with construction at the Winiker and the Varney sites are acceptable. The Siting Council agrees that, if the Varney site is used, uncertainties associated with rezoning and acquiring rights to contruct necessary gas and steam pipelines are likely to adversely affect NEA's ability to begin operating the plant by January 1990.

The Siting Council, however, cannot accept NEA's estimates of indirect costs that might be associated with scheduling delays, since there is inadequate evidence to indicate whether the net costs associated with interest rates, gas supply prices, and construction costs would go increase or decrease if the schedule were delayed.

Nonetheless, the Siting Council finds that NEA could incur about $5 million in additional direct costs if it constructed the facility at the Varney site. The Siting Council further finds that there is a substantial risk of significant scheduling delays associated with use of the Varney site.

Accordingly, the Siting Council finds that NEA has demonstrated that construction of the proposed facilities at the proposed Winiker site is preferable to the Varney site on the basis of cost.

4. Environmental Analysis of Facilities at the Proposed and Alternate Sites

In its filing, NEA has presented a detailed analysis[23] of the environmental impacts of the proposed facilities at both NEA's preferred Winiker site and one alternative site identified by NEA, the Varney site. The petitioner also discussed proposed and alternative available mitigation measures to minimize such impacts (Exhs. HO-1, HO-2). The Siting Council reviews NEA's analysis of the environmental impacts of the proposed cogeneration and ancillary facilities, evaluates the positions of NEA and the intervenors with respect to NEA's choice of site and mitigation plans, and determines which site is preferable in terms of environmental impacts.

a. Community Development and Zoning

NEA asserts that the Winiker site is appropriate for industrial development, and attractive relative to other identified sites for a gas-fired power plant in particular (Exh HO-16). Existing industial land uses are located nearby, both to the west of the Winiker site on a parcel occupied by Cove Machinery and to the north across Depot Street at the Bellingham Industrial Park (Exh. HO-2, p. V-39). Although residential developments are located nearby to the south and east of the Winiker site, NEA states that the Winiker site itself and adjacent areas south to Mendon Street and east to Depot Street are zoned as industrial (id.).

In addition to industrial zoning, NEA asserts that the Winiker site has other important attributes for a power plant, including a gas

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23/ NEA also has presented a more general environmental analysis that NEA used to screen possible sites over a wider geographic area and to assess environmental and other implications of alternative technologies for generating electricity. The Siting Council has reviewed separately NEA's approaches to screening possible sites in Section III.B.2, supra, and to assessing environmental implications of alternative technologies in Section II.C.3, supra.

pipeline traversing the site, a nearby 345 kV transmission line, nearby rail access, and an adequate water source (Exh. HO-16; Tr. V, p. 142). As further indication of the consistency of the proposed project with community development, NEA cites Town administrative actions already taken or expected relating to the proposed development of the Winiker site, including action by the Zoning Board of Appeals to grant a height variance for the plant stack (Tr. V, p. 107) and continuing negotiations between NEA and the Bellingham Water Department to allow utilization of a contaminated Town well to meet the plant's water requirement (id., pp. 131-132).

NEA asserts that the Winiker site is superior to the Varney site from the perspective of community development, since the Varney site is zoned for agricultural use (id., p. 142). The Box Pond Association also argues that the Winiker site is preferable to the Varney site, noting that the proposed plant is superior to likely alternative future uses of the Winiker site (Tr. VI, pp. 25, 26, 33-38). At the same time, Box Pond Association expresses opposition to rezoning the Varney site (id., p. 27).

No minimum industry or other standards with regard to total or active site area for a generating facility of the type proposed have been identified in this proceeding. NEA provided documentation showing that the proposed total and active site areas at the Winiker site conform reasonably well to the corresponding statistics for a number of comparable projects in the region (Exh. HO-E-13). At the same time, the Varney site, which is more than three times as large as the Winiker site, would provide considerably more space than most of the identified comparable projects (id.). Although NEA failed to provide any industry standards which might support the use of the Winiker site for a project of this size, the data on comparable projects provides some basis for Siting Council review.

The Siting Council finds that both the Winiker site and the Varney site can reasonably accommodate the proposed facilities.

Accordingly, the Siting Council finds that the proposed facilities will have an acceptable impact upon zoning and community development at either the Winiker site or the Varney site. The Siting

Council further finds that, based on zoning and community development concerns, the Winiker site is preferable to the Varney site.

b. Water Supply

NEA expects that the proposed plant will require 300,000 gallons of water per day, plus or minus ten per cent (Tr. V, p. 19; Exh. HO-E-1). NEA asserts that this requirement can be met by a single new well proposed to be drilled at an existing test well site owned by the Town of Bellingham, known as Well Number 9 (Tr. V, pp. 19-20).

NEA has provided monitoring well data from a 1968 pumpage test, showing the effects of pumpage on observed ground water levels at up to 1,000 feet from Well Number 9 (Exh. NEA-11). Based on these data, NEA concludes that long-term pumpage at a rate of 250 gallons per minute (360,000 gallons per day) or less will have a negligible effect on ground water levels at distances of 1,000 feet or more from the proposed new well (Tr. V, pp. 24, 28-29; Exh. HO-2, pp. VI-34 to VI-36). NEA states that Well Number 9 will be 2,600 feet from the nearest existing private well, and 1,900 feet from the nearest Town well (Exh. HO-E-5).

NEA also argues that the proposed use of Well Number 9 will not conflict with the Town's need to supply potable water to its other customers, since the 1968 pumpage test showed that Well Number 9 was contaminated with volatile organic compounds and unsuitable for potable use (Exh. HO-2, p. VI-34). Further, the Siting Council notes that NEA's proposed withdrawal rate is approximately 12 per cent of the Town of Bellingham's total municipal pumping rate as of July, 1987 (Exh. HO-E-5).

Accordingly, the Siting Council finds that the proposed facilities will have a minimal impact upon the Town of Bellingham's municipal water supply and existing private wells in the area.

c. Water and Land Environment

NEA asserts that the proposed generating facilities will occupy a nine-acre active area on the 44-acre Winiker site, and require the actual clearing of woods from 7.4 acres (Exh. HO-E-12). In addition, NEA states that the corridor for the proposed electric transmission line will extend westward to the existing Card Street transmission line right of way, traversing wetlands on the western edge of the Winiker site and requiring the clearing of woods from an additional 2.1 acres on both the Winiker site and the abutting Cove Machinery parcel (id.). NEA notes that the disturbed land areas will amount to a fraction of the total project area, and that the land and water impact will be less than that of other possible forms of development on the site (Exh. HO-2, p. III-6).

NEA asserts that the project will have no impact on water resources (Tr. V, p. 146). NEA argues that the potential for impacts on either surface water or ground water will be largely eliminated through incorporation of a zero discharge treatment and recycling system, together with a site drainage system utilizing gas/oil separators and detention basins (Exh. HO-2, p. V-40). In addition, NEA has argued that it reviewed all applicable law relating to wastewater discharge, solid waste disposal, and storage and handling of hazardous materials, and that it anticipates no problems in complying with these laws (Tr. V, pp. 74-76, 78-82; Exhs. HO-E-7, HO-25).

According to NEA, the transmission corridor will cross existing wetlands at a relatively narrow point, allowing the wetlands to be spanned without locating any transmission structures therein (Exh. HO-2, pp. VI-40, VI-41). Wetland impacts will be further minimized by locating the transmission corridor in the vicinity of the existing gas pipeline, although even this approach will necessitate the clearing of 0.3 acre of wooded wetland for the corridor (id.; Exh. HO-E-12).

NEA proposes to construct a steam conduit along a portion of the transmission corridor, including the wetland crossings (Exh. HO-2, p. VI-40). NEA acknowledges that a wetlands replacement area thus may be required under the Massachusetts Wetlands Protection Act (id., p. VI-41). NEA states the proposed conduit route still is preferable to an alternate steam-conduit route extending south to Mendon Street, which would avoid wetlands crossings but would double the total route length and possibly impact nearby residences (id.).

NEA reports that it analyzed flora at the Winiker site and found that both wetland and upland areas offer good food and cover for wildlife (id., pp. V-15 to V-16). However, NEA found that there was a "dearth of wildlife" there, and suggests that in-migration and occupation by wildlife may be inhibited by the densely populated human community (id., p. V-16). According to NEA, great blue heron feed on the Winiker site's wetlands, but no species classified as rare or endangered have been documented or observed anywhere at the site (id., p. V-40).

In comparing the proposed and alternate sites, NEA states the Varney site might prove more difficult to develop due to its agricultural zoning and its greater value as a wildlife habitat (id., pp. D-1, D-3 to D-6). Specific habitat values identified in NEA's analysis of the Varney site include upland white pine forests, as well as "edge habitats" located along the Charles River valley and an existing powerline right of way (id.). In addition, NEA argues that construction of the proposed facilities on the Varney site would result in companion industrial development there, while Box Pond Association asserts that the Winiker site would be used for alternative residential development (Tr. V, pp. 132-134, Tr. VI, pp. 25-26).

The Siting Council agrees that the Varney site appears to offer greater habitat values, including both the upland pine forest and the upland and wetland "edge" habitats. However, while construction of the proposed facilities on the Varney site could directly displace part or all of the upland pine forest, it is not clear that it would directly affect the edge habitats (id., p. V-9; Exh. HO-3). Indeed, the substantially larger Varney site would offer a greater opportunity to buffer adjoining wetlands and surface water areas from the proposed facilities. Thus, the greater potential direct loss of wildlife habitat at the Varney site is partially offset by the greater opportunity to buffer adjoining wetlands and surface waters there.

The arguments as to companion industrial development at the Varney site and alternative residential development at the Winiker site are speculative. Therefore, the Siting Council rejects the arguments of NEA and Box Pond Association concerning potential future land use.

Accordingly, the Siting Council finds that the proposed facilities will have an acceptable impact upon land and water environments at either the Winiker site or the Varney site. The Siting Council further finds that, based on overall consideration of water and land environments, the Winiker site is slightly preferable to the Varney site.

d. Electrical Effects of Transmission Line

NEA states that the proposed 345 kV transmission line will cross two parcels west of the Winiker site, known as the Cove Machinery parcel and the Rizzo parcel (Exh. HO-E-14). NEA does not anticipate any ongoing human presence in the vicinity of the transmission line, given that it will cross only industrially zoned land (id.; Tr. V, pp. 137-139).

NEA proposes to establish a right-of-way easement of 150 feet or more in width (Exh. HO-E-14). According to NEA, such a width will satisfy criteria applied by MDPU, criteria that NEA asserts account for noise levels, radio and television interference, and field strengths from the transmission line (Exhs. HO-E-20, HO-E-20A, HO-E-20B).

The Siting Council notes that the MDPU requirements address minimum clearances and other electrical design considerations relating in large part to the location of transmission lines relative to each other and any nearby objects. Still, the placement of lines relative to the edge of the right-of-way is significant for assessing electrical effects on abutting lands.

In a previous review of proposed transmission facilities, including 345 kV lines, the Siting Council addressed in detail the expected electrical effects of such facilities, notably the health implications of electric and magnetic fields.[24] Massachusetts Electric Company, 13 DOMSC 119, 228-242 (1985). In its review of the Hydro Quebec project, the Siting Council found that it was likely that the transmission lines proposed as part of that project would not adversely affect the health of Massachusetts residents, provided precautions were taken to minimize the known health effects (id., 241). However, the Siting Council found that additional research into the biological effects of electric and magnetic fields was warranted, and conditioned its approval of the proposed facilities in that review on the submission of a plan of study for possible further monitoring and research[25] (id., 241-242).

As NEA's proposed 345 kV line will be relatively short (about .25 mile for the Winiker site; a few hundred feet for the Varney site) and traverse uninhabited, industrially zoned land, the Siting Council has not conducted a similarly detailed evaluation of possible electrical effects in this proceeding. Nor has NEA provided evidence that it will establish a right-of-way corridor and design the proposed transmission line to be consistent with maintaining any particular field strengths under the line or at the edge of the right of way. However, NEA has noted that no residential development exists in close

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24/In the Hydro Quebec case, it was estimated that AC electric field would not exceed 1.8 kilovolts per meter and that AC magnetic field would not exceed 85 milligauss along the edge of the project rights of way in Massachusetts. Massachusetts Electric Company, 13 DOMSC 119, 228-229 (1985).

25/The range of possible effects on humans and biological resources includes those which have been known to occur in certain situation(s) involving electrical transmission (for example, shock, effects on pacemakers, effects on honey production by bees), and other potential effects that have been hypothesized and/or investigated but are not generally accepted as known or proven effects of electrical transmission (for example, effects on milk production by cows, headaches or other perceivable discomforts or symptoms in humans, chronic effects such as cancer in animals or humans).

proximity to the proposed transmission line route, nor is such development envisioned, based on the prevailing zoning.

Accordingly, the Siting Council finds that, based on current land use and zoning and NEA's project design plans, the proposed transmission line will have a minimal impact on noise levels, radio and television interference, and public health and safety in the surrounding community attributable to electrical effects.

e. Air Quality

NEA asserts that the proposed facility will utilize the cleanest-burning sources of fuel available, and will employ Best Available Control Technology ("BACT") consistent with state and federal requirements to minimize emissions of nitrogen oxides ("NOx") or resultant nitrogen dioxide ("NO_2"), sulfur dioxide ("SO_2"), particulates and carbon monoxide (Exh. HO-1, pp. IV-3). According to NEA, emissions will be maintained within national New Source Performance Standards ("NSPS"), and will result in ambient air quality concentrations that are still well below national and state ambient standards and within allowable national Prevention of Significant Discharge ("PSD") increments (id., pp. IV-2 to IV-7; Exhs. NEA-7A to NEA-7D).

NEA notes that the proposed plant site is geographically included in an existing "nonattainment area" (an area in which ambient standards are exceeded) for only one pollutant -- ozone (Exh. HO-1, p. IV-3). However, NEA asserts that the proposed plant falls below applicable review thresholds for ozone (Exh. HO-1, p. IV-4; Tr. IV, p. 38).

As part of its proposed BACT, NEA states that it will rely on distillate oil with a low sulfur content -- 0.08 per cent -- as a back-up fuel (Tr. IV, p. 44). Based on an expected maximum of 720 hours per year of burning oil, NEA asserts that the project's expected maximum SO_2 emissions of 65 tons per year would be insignificant when compared to an expected future statewide cap on SO_2 emissions of 417,000 tons per year (id., p. 45).

To meet BACT standards for NOx, NEA proposes to use steam injection to limit stack concentrations of NOx to 25 parts per million (ppm) at 15 percent oxygen on a dry basis when burning gas, and 42 ppm when burning oil (id., pp. 44, 60; Exh. HO-29). NEA notes that the proposed emission concentration for NOx is below the NSPS limit of 75 ppm, and states that the more stringent control level is necessary because of the MDEQE's intentions with respect to controlling precursors of acid rain (Tr. IV, pp. 63-64). Selective catalytic reduction ("SCR"), an alternative NOx control technology, also was considered by NEA but rejected on the grounds that it is unproven and costly (id., p. 93).

In regard to the possible cumulative impact on NO_2 from the proposed Ocean State Power project in Burrillville, Rhode Island and NEA's proposed Bellingham plant, NEA states that ambient NO_2 in Bellingham still will be much less than the state guideline of 320 micrograms per cubic meter ("ug/m^3") (id., p. 81). Based on information available at the time of the hearings, NEA estimated that the NO_2 contribution in Bellingham of the Ocean State Power plant will be approximately 16 ug/m^3; by comparison, NEA calculated that the contribution in Bellingham of NEA's plant will be 25.1 ug/m^3 assuming a stack concentration of 42 ppm[26] (id., pp. 80-81).

NEA has provided quantitative analyses to show the relative ability to meet applicable standards relating to air quality at both the Winiker and Varney sites (Exhs. NEA-7A to NEA-7D). NEA asserts that the Winiker site is preferable to the Varney site, based on NEA's perception that an area of concentrated population to the east and northeast would be relatively close to the Varney site, and also more exposed to plant emissions from the Varney site given prevailing winds (Tr. V, pp. 144-145).

26/After the close of hearings, NEA filed a record response indicating that the proposed NOx stack concentration when burning gas is 25 ppm rather than 42 ppm; thus the local contribution of NEA's plant will be less than 25.1 ug/m^3 when burning gas (Exh. HO-29).

NEA has presented maps and aerial photographs which indicate that a residential area approximately five to ten blocks wide extends from Middle Avenue, about one-half mile east-southeast of the Winiker site, to Hartford Avenue, about one mile northeast of the Varney site (Exhs. HO-E-11.C, HO-E-15). These maps and photographs indicate that the widest portion of this residential area is at a point east of the Varney site and northeast of the Winiker site (id.). NEA also has provided data on the relative frequency of the various wind directions for Worcester, which served as the basis of NEA's air quality modeling (Exh. HO-B-9.D(9), pp. 5-4 through 5-8).

The Siting Council notes that the Winiker site and the Varney site are essentially equidistant from the area of concentrated population to the east and northeast, and therefore must reject NEA's argument that there is a larger population concentration around the Varney site. With respect to prevailing winds, NEA's data indicate west is a more prevalent wind direction than west-southwest or southwest (Exh. HO-B-9.D(9), pp. 5-4 to 5-8). Considering only the widest portion of the area of concentrated population referred to by NEA, a prevailing west wind indeed could maximize air quality impacts from the Varney site. However, the data show differing conditions when broken out by wind speed, with west-southwest being equally or more prevalent for wind speeds of three meters per second or less (id.). Local concentrations of pollutants likely would be greatest when wind speed, and thus dispersion of pollutants, is relatively low. In any case, the Siting Council finds there is inadequate evidence to conclude that prevailing winds would result in significantly greater exposure of nearby population to air pollution if the proposed facilities were constructed at the Varney site.

In fact, NEA's own modeling of air quality conditions, based on modeling of second-worst-hour weather conditions from a five year period, places the Winiker site in a less favorable light (Exhs. NEA-7A to NEA-7D; Tr. IV, p. 83). Specifically, NEA's modeling shows that choice of the Winiker site would result in higher concentrations of pollutants than the Varney site under shorter averaging periods such as one-hour and three-hour (Exhs. NEA-7A to NEA-7D). NEA attributes such differences to a slight difference in elevation between the two sites, and to differences in distances to monitoring receptor points from the respective sites (Tr. IV, p. 82). While it appears possible that the relative locations of monitoring receptors may be a significant factor in the higher concentrations modeled for the Winiker site[27], the relative modeling results for the two sites cannot simply be disregarded.

NEA also discounts the second-worst-hour modeling results by noting that worst-hour weather conditions, which also were modeled by NEA, show no significant differences between the two sites (id., p. 83). However, the Siting Council notes that NEA's modeling for third-worst-hour weather conditions shows results similar to those for the second-worst hour (id., p. 85). Therefore, the second-worst-hour modeling results orignally presented by NEA cannot be ignored.

Accordingly, the Siting Council finds that, with the mitigation measures proposed by NEA, the proposed facilities will have an acceptable impact on air quality at either the Winiker site or the Varney site. Nevertheless, the Siting Council finds that, based on the expected air quality impacts, the Varney site is slightly preferable to the Winiker site.

f. Noise

NEA proposes to install silencers to reduce stack exhaust noise, as well as noise produced by the turbine inlets (Tr. IV, p. 116). Based on this proposed mitigation, NEA has predicted noise levels for four residential locations in the immediate vicinity of the Winiker site property boundary, indicating that the maximum nighttime

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27/The modeling results for both sites are mostly based on nearby, relatively uninhabited hilltop locations; for the one-hour NO_2 results, the Winiker concentration is for a hill a short distance to the east-northeast, while the Varney concentration is for a slightly more distant hill to the south (Tr. IV, p. 84; Exh. E-DOC-1.A).

noise level will be 48 decibels and that the maximum increase in nighttime noise over background levels will be seven decibels (Exhs. HO-23, HO-30). NEA concludes that the predicted noise impacts of the plant will comply with MDEQE guidelines relating to maximum allowable increases in noise from the project (Tr. IV, pp. 125-126).

In evaluating possible impacts of the proposal on indoor human activities, NEA's witness, Ms. Hooper, stated that certain studies indicate that interference with indoor conversation generally does not occur if outdoor noise is below 50 decibels (id., p. 143-146; Exh. NEA-10). Ms. Hooper also stated that it is very likely that the threshold for interference with sleep is higher than the maximum noise expected to be produced inside homes by the plant, assuming that the exteriors of residences provide an outdoor-indoor attenuation of ten decibels or more (Tr. VI, pp. 76-78; Exhs. HO-23A, HO-23B).

NEA also has noted that its noise analysis was conservative (i.e., tends to overestimate expected noise levels), and stated that adjustments for the conservative factors in its analysis would reduce the plant's predicted noise contribution by at least five decibels (Tr. VI, pp. 81-84).

NEA provided quantitative analyses showing the relative ability to meet applicable criteria relating to noise at both the Winiker and Varney sites (Exhs. HO-23, HO-30). NEA's analysis indicates that operation of the proposed facilities at the Varney site would result in a maximum residential-area nighttime noise level of 40 decibels, 8 decibels less than the corresponding level for the Winiker site (Exh. HO-23). The maximum increase in residential-area nighttime noise level would be four decibels with the plant in operation at the Varney site, compared with a maximum increase of seven decibels at the Winiker site (id.).

In its review, the Siting Council considers the likelihood that the project will result in noise impacts that are sufficiently small to avoid or minimize detectability and any related complaints by residential or other abutters. See Massachusetts Electric Company, 13 DOMSC 119, 232 (1985). NEA ackowledges that noise increases begin to be detectable by humans, although barely so, when such increases reach three or four decibels (Tr. IV, pp. 142-143). Given that the predicted noise increase in residential areas attributable to the proposed facilities is as high as seven decibels, there is a possibility that the increased noise may result in abutter complaints.

NEA has argued that conservative assumptions in NEA's noise analysis effectively overstate the predicted noise. Assuming NEA's adjustment factor of five decibels or more is correct, the likelihood of abutter complaints would be minimal. However, NEA's assertions as to the appropriate extent of adjustment for the conservative assumptions appear to be more judgmental than the original calculations of predicted noise.

The Siting Council finds that, with NEA's proposed mitigation measures, the proposed facilities will have an acceptable impact on community noise levels at either the Winiker site or the Varney site. Nevertheless, based on the relative predicted noise levels, the Siting Council finds that the Varney site is preferable to the Winiker site.

g. Visual Impact

NEA proposes to constuct a 190-foot stack, having reduced the proposed height from 220 feet in response to community concerns (Tr. V, pp. 106-108). NEA states that the proposed plant stack will be visible from parts of the surrounding community, but that the visual impacts of the plant building and other appurtenant structures will be mitigated by planned setbacks from roadways and residential areas, existing or new perimeter vegetation, and architectural design (Exh. HO-1, p. IV-26).

As an indication of stack visibility, NEA provided profile photographs showing views from residential areas toward the proposed and alternate plant sites with overlays of the stack outline (Tr. V, pp. 110-118; Exhs. HO-E-11.C.1 to HO-E-11.C.14). NEA also provided aerial photographs that show the extent of vegetation on residential streets in the area (Exh. HO-E-15). NEA argues that the stack will be continuously visible along essentially the full length of Rose Avenue off Mendon Street and directly along the north shore of Box Pond, but only intermittently visible along the lengths of other residential streets in the vicinity (Tr. V, pp. 117-118).

Box Pond Association notes that the visibility of the plant stack is a concern for its members, but states that it is a reasonable trade-off when compared to "a lot of house fronts right on the water" (Tr. VI, p. 37).

Based on the photographs and testimony, visual impacts are likely to be greatest along Rose Avenue off Mendon Street, and directly along the north shore of Box Pond (Exhs. HO-E-11.C.1, HO-E-11.C.2, HO-E-15). As noted by NEA and demonstrated in the aerial photographs, views from the homes themselves along Box Pond, situated back from the immediate shore, would be somewhat screened from the stack by trees (Tr. V, p. 117; Exh. HO-E-15). However, the Siting Council notes that seasonally, when leaves are off the trees, visual impacts may be greater than indicated in the photographs at residences along Box Pond, as well as in other residential neighborhoods near the plant site such as Judy Lane and Rose Avenue off Depot Street.

NEA testified that the plant stack would have a greater visual impact if constructed on the Winiker site, based on its expected visibility along Rose Avenue off Mendon Street, and along the immediate north shore of Box Pond (Tr. V, p. 117). With respect to the visual impact of the stack if constructed on the Varney site, NEA asserts visibility would be significant in one instance, specifically along a section of Grove Street (id., p. 118). However, the Siting Council notes that the stack would be closer to impacted residential areas if constructed on the Winiker site.[28] In addition, the aerial photographs show the relative openness of the section of Rose Avenue off Mendon Street, which would be affected by construction on the Winiker site (Exh. HO-E-15).

The Siting Council finds that the proposed facilities will have potentially significant visual impacts, in some instances, on

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28/The proposed stack location is 700 feet from the nearest residence at the Winiker site, and 1,800 feet from the nearest residence at the Varney site (Exh. HO-23).

residential areas up to 2,000 feet from the proposed stack location on the Winiker site. Selected tree plantings in such areas would be effective in mitigating visual impacts.

The Siting Council finds that the proposed facilities will have a minimal visual impact on the surrounding community at either the Winiker site or the Varney site, although visibility of the stack likely will vary significantly by location and by season. Further, the Siting Council finds that the Varney site is preferable to the Winiker site for minimizing the visual impacts of the proposed facilities.

h. Oil Back-Up

NEA has arranged with Bay State to exchange Bay State's oil for NEA's firm supply of natural gas for up to 30 days during a portion of the heating season (Tr. II, pp. 98-102, 152-155). In addition, NEA itself would need to burn oil if its gas supply is interrupted (id., p. 105).

To serve either purpose, NEA proposes to construct one or two oil storage tanks with a total capacity of 2.5 million gallons at the plant site (id., p. 161). NEA asserts that the oil storage tanks will be installed and positioned within the Winiker site consistent with safety and environmental standards (Tr. V, pp. 82, 85-89).

Bay State indicates that any necessary oil supplies may be delivered to the plant site by tank truck, but that rail access and off-loading capabilities also will be available (Tr. II, pp. 161, 176). Bay State asserts that installation of an oil pipeline into the Winiker site along the Algonquin right-of-way may be possible in the future, should Bay State's actual takes of NEA's gas warrant such a delivery capability for replacement oil (id., p. 178).

In this proceeding, NEA has not provided an analysis of predicted noise impacts associated with Bay State's fuel hauling under the life of the agreement. In citing some examples of typically encountered community noise levels, NEA has noted that a diesel truck can create a noise level of 90 decibels at a distance of 50 feet (Exh.

HO-1, p. IV-17). NEA also has stated that the plant manager typically would help resolve any concerns as to times of the day when deliveries are made, considering factors such as overtime costs and the extent if any to which neighbors of the plant might be bothered by truck traffic at particular hours (Tr. V, p. 127).

With respect to the frequency of deliveries under the Bay State agreement, NEA suggests as a worst-case scenario that there could be up to 600 fuel-truck deliveries over 30 days, or 20 trips per day both into and out of the plant site (id., pp. 125-126). However, Bay State states that it expects to utilize only a fraction of NEA's 30-day equivalent gas supply through the end of the 1990's, requiring NEA to use no more than 1.285 million gallons of replacement oil per heating season in the first few years and no more than 3.213 million gallons in the later years of the decade (Tr. II, pp. 173-174, 182; Exh. HO-CFO-3). Noting that maximum daily drawdown is 370,000 gallons, Bay State asserts that worst-case refill requirements during the heating season itself probably would not exceed 1.2 million gallons for the season in the early years of the agreement (Tr.II, p. 183). As envisioned by Bay State, drawdowns during the early years probably would be so spaced as to allow refilling with ten to 15 truckloads of oil a day, a rate Bay State characterizes as "very little oil trucking" (id., pp. 182-183).

The Siting Council agrees that the rates of backup oil delivery planned in the early years of the agreement are not likely to create an unacceptable nuisance. Yet, given Bay State's plan to increase its takes of NEA's gas over time, the Siting Council finds that careful planning by both Bay State and NEA, done in consultation with community representatives, will be essential for ensuring that the required oil is delivered to NEA with a minimum impact on the environment. Such planning should address the routing and scheduling of any necessary tanker truck deliveries in the Bellingham area, as well as options for using rail or pipeline delivery instead of trucking.

The Siting Council finds that the facility's expected requirements for delivery and storage of back-up fuel oil will have a minimal impact on the environment.

i. Conclusion

The Siting Council finds that, with the environmental mitigation proposed by NEA, the proposed facilities will have an acceptable impact on all of the environmental concerns addressed in this proceeding, whether constructed at the Winiker site or the Varney site.

Further, the Siting Council finds that, with the environmental mitigation proposed by NEA, the Winiker site is preferable to the Varney site with respect to concerns relating to (1) community development and zoning and (2) water and land environments, while the Varney site is preferable to the Winiker site with respect to (1) air quality, (2) noise impacts, and (3) visual impacts. The Siting Council finds that, on balance, the Varney site is slightly preferable to the Winiker site in terms of environmental impacts.

5. Reliability Analysis of the Proposed and Alternate Sites

The record in this proceeding is silent on the question of whether the reliability of the power generated at and transmitted from the NEA plant constructed and operated at NEA's proposed Winiker site is superior to the reliability of power generated at and transmitted from the alternate Varney site.

Accordingly, the Siting Council finds that there is no preference between the Winiker and Varney sites on the basis of reliability of supply.

6. Conclusion

The Siting Council has found that NEA has demonstrated (1) that construction of the proposed facilities at the proposed Winiker site is preferable to the alternate site on the basis of cost, (2) that construction of the proposed facilities at the alternate site is slightly preferable on the basis of environmental impacts, and (3) that there is no preference between the proposed and alternate sites on the basis of reliability of supply.

The Siting Council finds, however, that the cost (including scheduling) advantages of the Winiker site outweigh the slight environmental advantages of the Varney site.

Accordingly, the Siting Council finds that, on balance, the proposed Winiker site is superior to the alternate Varney site in terms of cost, environmental impacts, and reliability.

However, in order to mitigate the adverse visual and noise impacts associated with constructing the proposed facilities at the Winiker site, the Siting Council ORDERS NEA:

(1) to (a) periodically measure the noise levels at the residence nearest to the plant for two years after initial operation of the plant, and (b) maintain records of any noise complaints received during the first two years of operation and report to the Siting Council on the nature and resolution of all such complaints.

(2) to provide selective tree plantings along residential streets and public ways up to 2,000 feet from the proposed stack location in order to reduce the visibility of the stack to an extent that the stack will only be intermittently seen while traveling along such streets or public ways, consistent with a representative extent of tree planting as now exists on residential streets within a mile of the plant stack. Specifically, NEA shall provide tree plantings along the west side of Rose Avenue off Mendon Street, extending from the last utility pole on the west side of Rose Avenue to just beyond the driveway of the last existing residence on that side (both as visible in Exhibit HO-E-11.C.1), and on a selective basis as requested by residents and as reasonable along other streets or sections thereof up to 2,000 feet from the stack location;

NEA shall make such plantings on residential property only with the permission of the affected property owners, and in public ways only with the permission of appropriate Town officials and abutting property owners; NEA shall be responsible for maintaining or replacing such plantings as necessary to ensure that healthy plantings become established; local residents and Town officials may request tree plantings up to six months after initial operation of the plant; NEA shall complete all such plantings within one year after completion of construction of the plant stack or, if based on a request after completion of the stack, within one year after such request; and NEA shall provide notice of this order to appropriate Town officials and to all owners of residential properties within 2,000 feet of the project stack, within 60 days of this decision and, again, within 60 days of completion of the stack.

IV. CONCLUSION AND ORDER

The Siting Council finds that construction of the proposed facilities at the proposed Winiker site is consistent with providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

The Siting Council hereby APPROVES the petition of Northeast Energy Associates to construct a bulk power generating facility, an electric transmission line, a natural gas pipeline, and oil storage facilities, subject to the following conditions:

(1) NEA shall (a) periodically measure the noise levels at the residence nearest to the plant for two years after initial operation of the plant, and (b) maintain records of any noise complaints received during the first two years of operation and report to the Siting Council on the nature and resolution of all such complaints.

(2) NEA shall provide selective tree plantings along residential streets and public ways up to 2,000 feet from the proposed stack location in order to reduce the visibility of the stack to an extent that the stack will only be intermittently seen while traveling along such streets or public ways, consistent with a representative extent of tree planting as now exists on residential streets within a mile of the plant stack, and consistent with the directives set forth in Section III.B.6.

Robert D. Shapiro

Robert D. Shapiro
Hearing Officer

Dated this 18th day of December, 1987.

APPROVED by the Energy Facilities Siting Council on December 18, 1987 by the members and designees present and voting: VOTING IN FAVOR: Sharon M. Pollard (Secretary of Energy Resources); Barbara Anthony (for Paula W. Gold, Secretary of Consumer Affairs); Stephen Roop (for James S. Hoyte, Secretary of Environmental Affairs); Paul McNally (for Joseph Alviani, Secretary of Economic Affairs); Madeline Varitimos (Public Environmental Member). VOTING AGAINST: Stephen Umans (Public Electricity Member). INELIGIBLE TO VOTE: Dennis LaCroix (Public Gas Member). Absent: Joseph Joyce (Public Labor Member).

Sharon M. Pollard

Sharon M. Pollard, Chairman

December 18, 1987

Date