Decisions and Orders

Massachusetts Energy Facilities Siting Council

Volume 12

Publication #14,076-274-125-6-85-C.R.
Approved by Daniel D. Carter, State Purchasing Agent

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FINAL DECISION

James G. White, Jr.
Hearing Officer

On the Decision:
George H. Aronson

The Massachusetts Energy Facilities Siting Council ("Siting Council") hereby APPROVES the Petition of Algonquin SNG, Inc. ("Algonquin SNG" or "the Company"), for Approval of the Third Supplement to its Second Long-Range Forecast ("Supplement").

Introduction

Algonquin SNG owns and operates a single synthesized natural gas ("SNG") production facility located in Freetown, Massachusetts. Algonquin SNG sells the SNG to its parent company, Algonquin Gas Transmission Company ("Algonquin Gas"), for resale to gas distribution companies in Massachusetts, Rhode Island, Connecticut and New York under the SNG-1 rate schedule. In the 1983-84 heating season, Algonquin SNG sent out 5168.112 million cubic feet ("MMCF") of SNG.

History of the Proceedings

The Company filed its Supplement with the Siting Council on August 31, 1984. The Company provided notice of the adjudication to the public by publication and posting. The Siting Council received no petitions to intervene. Algonquin SNG provided complete responses to one set of Information Requests of the Siting Council Staff.

Description of the Forecast

As a producer of SNG with no retail sales, Algonquin SNG does not forecast sendout requirements. Instead, the Company forecasts the amount of SNG that it will sell to Algonquin Gas for resale to gas distribution companies. Over the forecast period, Algonquin SNG forecasts sales as follows:

Distribution Company	Peak Day Quantity[1] (MMCF)	Scheduled Annual Delivery Quantity (MMCF) 1984-85	1985-86	1986-87
Commonwealth Gas	21.881	1,179.526	734.000	747.424
Boston Gas	3.097	96.000	0.000	0.000
Fall River Gas	5.500	302.500	108.500	93.000
Colonial Gas, Cape Division	4.071	305.325	187.266	62.000
Outside of Massachusetts	30.268	1,306.822	768.588	552.646
Total production	64.817	3,190.173	1,798.354	1,455.070

Source: Supplement, Section I, at 2; EFSC Docket No. 84-34, Response to Staff Information Request I-2.

These delivery levels reflect reductions in contractual amounts for sale under Algonquin Gas's revised Rate Schedule SNG-1 ("Revised Schedule") as accepted by the Federal Energy Regulatory Commission ("FERC") on November 30, 1984. The Revised Schedule is the result of

1 Peak quantities during January, 1985. Actual peak quantities vary from month to month as shown on Algonquin Gas's SNG-1 tariff sheets (Second Revised Sheet No. 343). See Response to Staff Information Request I-2.

negotiated agreements between Algonquin Gas and the gas distribution companies that purchase SNG-1. By virtue of the agreements, Algonquin Gas granted its customers reductions in their annual purchase requirements, and expanded their flexibility in requesting SNG quantities.

The Siting Council is pleased that Algonquin Gas has complied with its customers' requests for reductions in SNG-1 purchase requirements and expanded flexibility. The Siting Council encourages the Company to continue its negotiations with its customers as appropriate.

The contracts between Algonquin Gas and its customers for service under the SNG-1 rate schedule all expire on October 1, 1987.[2] Algonquin SNG assumes that the SNG contracts will stay in effect (and that its production levels will stay constant) through the 1988-89 heating season, inasmuch as Algonquin Gas has not yet received any written notices of termination from current purchasers of SNG-1. Nevertheless, some or all of these purchasers may give the required notice on or before October 1, 1986, thereby changing the demand for SNG production.

Algonquin SNG's willingness to operate the facility after 1987 will depend on the seasonal volumes and production rates requested by the customers. Algonquin SNG states that it will operate the plant for any period of time provided it receives an adequate return for its services. However, facility operation is constrained by engineering and economic considerations. Currently, the minimum daily SNG production rate is approximately fifty percent of the plant's design capacity of 120.675 MMCF per day[3]. At lower production rates, Algonquin SNG states that plant efficiency and reliability decline substantially. Additionally, Algonquin SNG estimates fixed charges (insurance, taxes, labor, etc.) for the plant in 1987 to be approximately $14 million in 1984 dollars, with an additional cost of $4 million to maintain the plant in "cold

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2 The SNG-1 contracts will continue in effect after October 1, 1987, subject to termination on twelve months' prior notice by any party. Algonquin SNG does not require an abandonment authorization from FERC in order to cease plant operation, though Algonquin Gas appears to require abandonment authorization prior to the termination of service under its SNG-1 rate schedule. Supplement, Section I, page 2; Response to Staff Information Request I-6.

3 The daily production rate is not necessarily the same as the sum of the maximum daily quantities for all of Algonquin Gas's customers under the SNG-1 rate schedule. Differences between the plant production rate and the sum of all of the customers' daily takes are accounted for through a negotiated set of displacement and make-up arrangements. For example, though the SNG-1 rate schedule shows takes of SNG-1 as low as 5.342 MMCF per day (in December 1987), the plant rarely operates at production rates below 60 MMCF per day. When daily takes of SNG-1 are low, Algonquin Gas supplies its customers by displacement. When daily takes rise (in January), Algonquin SNG operates the SNG plant at production rates that are higher than the contractual daily takes, thereby making up the volumes supplied earlier by displacement.

standby"[4] for December and March, and "hot standby" for January and February[4]. Algonquin SNG indicates that these costs are a significant consideration in an analysis of the value of maintaining plant operations at various production rates. (Responses to Staff Information Requests I-5 and I-6). Given these considerations, the Siting Council notes it is uncertain whether Algonquin SNG will run the plant after 1987 in the absence of contractual commitments at or at least near current levels.

The Siting Council notes that continued operation of the SNG facility after 1987 will have both benefits and costs. The benefits include: the historical reliability of the SNG plant, regarding both plant operation and the availability of naphtha feedstock; the complete interchangeability of SNG with pipeline natural gas; the ability to deliver SNG through the existing distribution systems; and the economic benefits of operating a fully-depreciated plant. On the other hand, the Siting Council notes that the unit cost of SNG is quite high relative to the other sources of gas available to Massachusetts distribution companies. Algonquin SNG indicates that the price position of SNG versus other supplies is unlikely to change in the foreseeable future (Response to Staff Information Request I-3).

The Siting Council cannot determine from this record how these costs and benefits compare. Such a comparison requires an analysis of the role of SNG-1 in the supply plan of each purchaser of SNG.

Nevertheless, the SNG facility plays an important part in the Massachusetts natural gas supply picture, and the Siting Council is interested in monitoring its status. The Siting Council encourages the Company to continue to negotiate with its customers regarding the viability of the SNG facility after the expiration of current contracts, and to report on the status of these negotiations in more detail in its next filing.

Decision and Order

The Massachusetts Energy Facilities Siting Council hereby APPROVES the Petition of Algonquin SNG, Inc., for Approval of the Third Supplement to its Second Long-Range Forecast. The Fourth Supplement shall be filed with the Siting Council no later than September 3, 1985.

James G. White, Jr.

On the Decision:
George H. Aronson

James G. White, Jr.
Hearing Officer

Dated at Boston this 31st day of Dec., 1984.

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4 In "cold standby", the SNG plant is maintained at a temperature high enough to avoid freezing of various plant components. In "hot standby", the plant is able to produce SNG on reasonably short notice. In Re Algonquin SNG, 10 DOMSC 60, 65 (1983).

Unanimously APPROVED by the Energy Facilities Siting Council on December 20, 1984, by those members and designees present and voting: Chairperson Sharon M. Pollard (Secretary of Energy Resources); Sarah Wald (for Paula W. Gold, Secretary of Consumer Affairs); Stephen Roop (for James S. Hoyte, Secretary of Environmental Affairs); Dennis J. LaCroix (Public Member, Gas); Robert W. Gillette (Public Member, Environment); Joseph W. Joyce (Public Member, Labor).

January 7, 1985
Date

Sharon M. Pollard
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of the Blackstone Gas Company for Approval of its Annual Supplement to the Second Long-Range Forecast of Gas Requirements and Resources	)	Docket No. 84-42

FINAL DECISION

The Massachusetts Energy Facilities Siting Council ("the Council" or "EFSC") hereby APPROVES the Annual Supplement to the Second Long-Range Forecast of Gas Requirements and Resources of the Blackstone Gas Company ("Blackstone" or "the Company").

I. INTRODUCTION

The Blackstone Gas Company sells natural gas to 509 residential and commercial customers in the towns of Blackstone and Bellingham. Blackstone is the smallest gas company in the Commonwealth. In the 1983-84 split-year Blackstone's annual sendout was 41.7 MMcf, less than .03 percent of the total statewide sendout.[1] The Company has a contract with the Tennessee Gas Pipeline Company (Tennessee) for all of its gas requirements and purchases no supplemental supplies.

II. SUMMARY OF PROCEEDINGS

On May 30, 1984, the Council notified Blackstone that it was required by Mass. Gen. Laws Ann. ch. 164, sec. 69I, to submit an annual filing to the Council containing the Company's projected sendout requirements and resources for the ensuing five year period. The Council Staff met with Blackstone on June 27, 1984. The Staff and the Company agreed on the information to be included in the filing. On July 2, 1984, Blackstone filed its Annual Supplement to its Second Long-Range Forecast. Pursuant to Rule 13.2, the Company was ordered to post Notice of the Adjudicatory Proceeding on July 10, 1984. The Council received no requests to intervene or otherwise participate in this proceeding.

III. ANALYSIS OF THE SUPPLEMENT

A. Standards of Review

The Council uses three criteria to review the methodologies used in Forecast Supplements. Rules 69.2 and 66.5. Every gas company under the Council's jurisdiction must use a reviewable forecast methodology that is appropriate to its particular system and reliable in its ability to forecast future gas requirements and sendout.

1. EFSC Gas Supply and Demand Data Base, Table G-5.

Given Blackstone's size and position as an "all-requirements customer" of Tennessee, the Council previously required Blackstone to submit only Tables G-5 and G-24.[2] At the June 27, 1984 meeting with Blackstone, Council Staff reaffirmed this requirement and suggested that the Company use a "narrative" filing format.

Blackstone has submitted Tables G-5 and G-24 along with a narrative filing which provides data on the number of residential heating, residential nonheating, and commercial customers and the percent sendout for each customer class. Blackstone also submitted its bills for gas purchased from Tennessee from June 1983 through May 1984.

B. Forecast Methodology

1. Description and Analysis of Forecast Methodology

Blackstone's forecast methodology relies entirely on the "expert judgement" of the Company's president. Given the system's small size and all-requirements status, this technique is appropriate. The Company's 1981 narrative filing is particularly revealing as to the value of "expert judgement" as a forecast methodology.

> "The Company is operated by three officers and one employee, all of whom have years of utility industry experience. Both the President and Vice President have on scores of occasions read every meter in the system,... conferred with customers concerning the present and prospective use of gas and observed types of dwellings, the modes of heating and other use of energy, and through such activities have a practical basis for anticipating supply and distribution problems."[3]

Although appropriate for a company of Blackstone's size, this type of forecast methodology is not readily reviewable and does not provide basic background information necessary for proper review. To assist the Council in evaluating its forecast supplements in the future, the Council requests that the Company include in its narrative filing a brief description of the forces and trends which the Company expects to affect its sendout requirements (e.g., increased gas prices which increase conservation and reduce the rate of oil-to-gas conversions). Access to such information will help the Council to evaluate the reliability of the Company's judgemental forecast in the future.

Table 1 lists the Company's forecast of normal year sendout for the forecast period, and the projected percentage increases in the heating season and annual sendouts. These increases are limited to the heating season and thus increase Blackstone's heating season and peak day requirements. (See III.D, *infra*).

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2. In Re Blackstone Gas Co., 4 DOMSC 201 (1980).
3. Blackstone Gas Co., Docket No. 81-42 (Forecast at 1).

TABLE 1
Forecast of Normal Year Sendout
(Mcf)

Year	Forecast of Normal Sendout: Non-heating Season	Heating Season	Percentage Increase in Heating Season Sendout	Percentage Increase in Total Sendout
1984-85	15,500	26,000	-	-
1985-86	15,500	27,000	3.8	2.4
1986-87	15,500	28,000	3.7	2.4
1987-88	15,500	28,500	1.8	1.1

Source: Supplement, p. 3.

C. Resources

Blackstone's total gas supply is provided by Tennessee under its Small General Service (GS-6) rate schedule. Blackstone's contract with Tennessee expires in November, 2000 and provides a maximum daily quantity (MDQ) of 505 thousand cubic feet (Mcf) with an annual volumetic limitation (AVL) of 145,105 Mcf. These volumes are not augmented by any supplemental supplies. Tennessee has filed with the Federal Energy Regulatory Commission (FERC) for a Certificate of Public Convenience and Necessity which would provide for increases in its daily and annual delivery obligations to Blackstone to 519 Mcf per day and 149,685 Mcf per year. This application is currently pending before FERC.

D. Comparison of Resources and Requirements

Blackstone's Tennessee AVL is more than adequate to meet design and normal year requirements. For example, the 1984-85 normal year forecasted sendout (41,500 Mcf) is less than one-third of the Company's AVL (145,105 Mcf.) Blackstone's ability to meet its peak day requirements, however, is less evident. Nonetheless, Blackstone is formally exempted from forecasting peak load since neither Blackstone nor Tennessee collect daily load data.[4] Peak day requirements, however, are a critical parameter in evaluating the adequacy of Blackstone's resources. If the Company is able to meet peak day requirements with its Tennessee MDQ then the company's cold snap, design year, and normal year heating requirements can be met. Given the importance of peak day requirements in determining the adequacy of Blackstone's supply and the projected increases in Blackstone's heating season sendout requirements, the Council requests that in its next filing, Blackstone estimate its peak day requirements and indicate the penalty for exceeding its Tennessee MDQ.

4. In Re Blackstone Gas Co., 6 DOMSC 69 (1981)

Therefore, the Council finds that Blackstone's resources are more than adequate to satisfy its requirements in both normal and design years and under cold snap conditions.

IV. DECISION AND ORDER

The Council hereby APPROVES without conditions the Annual Supplement to the Second Long-Range Forecast of the Blackstone Gas Company. The next Annual Supplement is due on July 1, 1985.

By James G. White, Jr.

James G. White, Jr.

Dated at Boston this 3rd day of Jan, 1985.

Unanimously APPROVED by the Energy Facilities Siting Council at its meeting on December 20, 1984, by those members and designees present and voting: Chairperson Sharon M. Pollard (Secretary of Energy Resources); Sarah Wald (for Paula W. Gold, Secretary of Comsumer Affairs); Stephen Roop (for James S. Hoyte, Secretary of Environmental Affairs); Dennis J. LaCroix (Public Gas Member); Joseph W. Joyce (Public Labor Member); Robert W. Gillette (Public Environmental Member).

January 7, 1985

Date

Sharon M. Pollard

Sharon M. Pollard
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Fall River Gas Company for Approval of the Third Supplement to its Second Long-Range Forecast of Gas Requirements and Resources	)	Docket No. 84-20

FINAL DECISION

James G. White, Jr.
Hearing Officer

On the Decision:
George H. Aronson
John Dalton

The Energy Facilities Siting Council ("Siting Council") hereby APPROVES subject to CONDITIONS the Third Supplement ("Supplement") to the Second Long-Range Forecast of natural gas requirements and resources for the years 1984 through 1989 ("the forecast period") of the Fall River Gas Company ("Fall River" or "the Company").

I. Introduction and History of the Proceedings

Fall River distributes and sells natural gas to approximately 41,000 customers in the City of Fall River and the Towns of Somerset, Swansea, and Westport. Total firm sendout in the 1983-84 split year was 5481 million cubic feet ("MMcf"), which makes Fall River the fifth largest gas distribution utility in Massachusetts. Approximately 63 percent of the Company's firm sendout goes to residential heating customers, 23 percent to industrial customers, 8 percent to commercial customers, and 2 percent to residential non-heating customers. Between 1979 and 1983, Fall River's number of firm customers grew by 4.14 percent, though its weather-normalized firm sendout declined by 3.96 percent. Over the forecast period Fall River projects that it will increase its number of firm customers by 3.20 percent, and that its normal firm sendout will remain approximately constant.

Fall River filed the current Supplement on August 15, 1984.[1] The Company provided notice of this proceeding to the public by publication and posting in accordance with the directions of the Hearing Officer. The Hearing Officer granted the petition to intervene of Distrigas of Massachusetts Corporation ("DOMAC"). A formal hearing was not conducted. Instead, the record in this case was compiled through a written discovery process. The Company submitted responses to Information Requests prepared by the Siting Council staff. Those responses, along with the original Supplement, comprise the record for this case.

II. Compliance with Conditions

In its Decision on the Company's previous Supplement, Fall River Gas Company, 10 DOMSC 165 (1984), the Siting Council qualified its approval with the following three Conditions:

> 1. Within ninety days Fall River Gas Company will provide to the Siting Council a compliance plan for presenting a complete and systematic method of documenting its forecast methodology. The Company shall meet with the Siting Council Staff within thirty days to discuss preparation of the compliance plan.
>
> 2. As part of the next Supplement, Fall River Gas Company shall provide statistical justification for its design year degree day standards.

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1. The Fall River Gas Company ("Fall River" or "the Company") requested and was granted an extension in its filing date.

3. In its next Supplement, Fall River Gas Company shall include an LNG contingency plan and a detailed cold snap analysis.[2]

Pursuant to Condition 1, the Siting Council Staff met with representatives of the Company on April 4, 1984. On May 8, 1984, the Company submitted a document entitled "Compliance Plan Regarding Improvements to Documentation of Gas Sendout Forecast Methodology," which reflected Company's understanding of the results of the compliance meeting.

The Siting Council is pleased with the Company's efforts to improve the documentation of its forecast methodology. The instant Supplement contains sufficient explanations and back-up data for the Siting Council to reproduce most of the Company's calculations, and to appreciate most of the judgements underlying the forecast. The Company has not only complied with Condition 1, it has produced a document that is thoroughly reviewable.[3]

Pursuant to Condition 2, Fall River has submitted a complete set of split-year degree day data from 1963-64 through 1983-84, along with a narrative and two exhibits that explain its methodology for selecting normal and design weather standards. The Siting Council finds that the Company has complied with Condition 2, as described in Section III.A., supra.

Pursuant to Condition 3, Fall River has submitted a cold snap analysis and back-up table in its Supplement. As described more fully herein, the Council continues to have concern with the Company's cold snap standard and Orders the Company to develop a standard which reflects realistic weather conditions. The Company's Supplement does not contain an LNG contingency plan as requested in last year's decision. 10 DOMSC at 177. Accordingly, the Council reimposes this request as an Order.

III. Analysis of the Forecast Methodology

A. Introduction

Table 1 shows Fall River's forecast of sendout requirements for the 1984-85 and 1988-89 split years.

In this Supplement, Fall River continues to forecast its sendout requirements with the use of base factors, heating factors, and degree-day data. The Siting Council described this forecasting approach as "basically sound" in its previous Decision.[4] That Decision also described the Company's calculation procedures in some detail.

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2. 10 DOMSC 165, 179 (1984).
3. See 10 DOMSC 181, 190 (1984) for a definition of the reviewability standard.
4. 10 DOMSC 165, 169 (1984).

Table 1

Forecast of Sendout by Customer Class
(MMCF)

	1984-85 Non-heating Season	1984-85 Heating Season	1988-89 Non-heating Season	1988-89 Heating Season
Normal Weather				
Residential				
Heating	1115	2420	1110	2419
Non-heating	54	48	51	45
Commercial	141	315	151	335
Industrial	621	695	640	693
Co. Use and Unaccounted-for	(4)	236	0	236
Total Firm	1928	3693	1952	3729
Interruptible	842	150	842	150
Total Sendout	2770	3843	2794	3879
Design Weather Total Firm	2052	3847	2053	3880
Peak Day Sendout Requirements		48.7		49.2

Source: Supplement, Tables G-1 through G-5. Columns may not add due to rounding.

This Decision does not repeat descriptions contained in the previous Decision or in the Supplement itself. Instead, the Siting Council concentrates on aspects of the methodology that the Company has changed since its previous filing, or that the Company has described in sufficient detail for the Siting Council to review for the first time. These aspects include: the Company's method of selecting degree-day totals for normal and design weather; the methods of projecting base and heating factors; the basis for projecting the number of customers; judgmental adjustments to the forecast of commercial and industrial usage; and the new peak day forecast methodology.

B. Degree-day Totals

Fall River uses the following degree-day ("DD") totals to calculate its sendout requirements:

	Non-heating Season	Heating Season	Total Split-year
Normal Weather	1372	4751	6123
Design Weather	1543	5100	6643

The Company bases its DD totals on twenty years of weather data.

The DD totals for normal weather are the mean values for each season after deletion of outlying data points.[5] The DD totals for design weather are the maximum values actually experienced during non-heating seasons and heating seasons since the 1963-64 split year.

Regarding the Company's normal year standard, the Siting Council notes that the applicability of the Company's judgments can be confirmed by quantitative methods. For example, the median degree-day value exceeds the mean degree-day value for the non-heating and heating seasons since 1963-64.[6] Also, removal of the outliers reduces the standard deviation of the DD data by more than ten percent in each case. Thus, the Siting Council is satisfied that the Company's normal weather DD standards, including its judgemental deletion of outlying data points, are appropriate.

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5. The Company discards four outliers before calculating the average DD in a non-heating season, and discards one outlier before calculating the average DD in a heating season. The resulting weighted averages yield higher normal year DD standards than would result from the usage of unadjusted averages. See Supplement, Exhibits A and B.

6. The median values are 1370 DD for twenty non-heating seasons and 4735 DD for twenty heating seasons, while the mean values are 1351 DD for twenty non-heating seasons and 4725 DD for twenty heating seasons.

Regarding the Company's design year standard, the Siting Council notes that the Company has increased its design weather non-heating season DD standard since its previous Supplement. The Siting Council finds that Fall River has used an appropriate method to select its new standard and has complied with Condition 2.[7]

The Siting Council appreciates the Company's documentation of its degree-day data and its judgements in interpreting the data.

C. Base and Heating Factor Projections

Fall River projects base and heating factors for its residential sendout forecast through the use of trends selected on the basis of judgement. The Company assumes that base and heating factors will decline at constant rates from their 1983-84 values as shown below:

Customer class	Factor	1983-84 value *	Annual Decrement (absolute value)	Annual Decrement (percent)
Res. Non-Heating	Base	17.7	0.1	0.6%
Res. Heating	Base	27.7	0.3	1.1%
Res. Heating	Heating	0.0135	0.0001	0.8%

Source: Forecast, Tables G-1 and G-2. Decrements calculated from data in tables.

Note: Base factors are given in units of Mcf per customer. Heating factors are given in units of Mcf per DD per customer.

The Company states that it considers the impacts of appliance efficiency, conservation, gas deregulation and fuel cost expectations in its selection of these trends, but does not present quantitative studies of these impacts, nor has it planned any studies in these areas (Response to Staff Information Request SR-1).

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7. The Siting Council notes that Condition 2 did not require an increase in the design DD standard, but merely "statistical justification." Selection of the worst actual occurrence in each season over a given time period is appropriate, but other, more analytical approaches would be acceptable as well. Based on the DD data in the Supplement, an average Fall River heating season has 4725 DD with a standard deviation of 244 DD, while an average Fall River split-year has 6076 DD with a standard deviation of 293 DD. Assuming these data are normally distributed, the Company faces a probability of 0.0559 (1 in 18) of a colder-than-design heating season, and a probability of 0.0099 (1 in 100) of a colder-than-design split year. The latter figure is surprisingly low because of the use of an outlying actual data point for the non-heating season design standard. The Siting Council would accept a different standard if it were justified statistically.

The Siting Council questions the reliability of the use of judgemental trending to forecast base and heating factors without any quantitative linkage to causative factors. The Siting Council notes that the trends in base and heating factors in the Company's current Supplement are almost exactly the same as those presented in the Company's previous Supplement, though the starting points (i.e., actual data from the previous year) seem to diverge from historical trends. A methodology that produces substantially different data after the addition of one set of actual data points does not inspire confidence in the robustness of its results.

However, the Siting Council recognizes that Fall River forecasts minimal growth, and no new construction of facilities. Under these circumstances, the Siting Council finds that the methodology used to forecast residential base and heating factors is acceptable for a Company of Fall River's size and supply situation, despite our reservations regarding its reliability and robustness.

Nevertheless, the Siting Council believes that the Company should begin to collect data that support its judgements, that explain usage patterns for its customer classes, and that quantify the changes in its sendout requirements. Therefore, the Siting Council CONDITIONS its approval of Fall River's sendout forecast on the commencement of data collection efforts to support the Company's selection of trends in base and heating factors in future forecasts. The Company shall meet with the Staff of the Siting Council to discuss compliance with this Condition, affixed hereto as Condition 1. The Siting Council suggests that appropriate data collection efforts would include, but not be limited to: better integration of Company marketing data into the forecast; econometric studies of the relationship between price and base factors or heating factors; formal surveys of the number of appliances owned by the Company's present and future customers, the average use per appliance, and factors that influence appliance ownership and usage by residential heating and non-heating customers; and closer examination of residential heating consumption patterns and the price and temperature-sensitivity of residential non-heating load.

For its residential non-heating customer class, Fall River forecasts annual sendout, then allocates sendout to the heating and non-heating seasons on the basis of the historical percentage of sendout in each season. This historical percentage is the average of the ratio of heating season sendout to annual sendout for each of the last nine years.

The Siting Council notes that the ratio of heating season sendout to annual sendout for the residential non-heating class has stayed relatively constant over the last nine years, despite variations in the allocation of degree-days between the heating and non-heating seasons[8].

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8. The average ratio over the last nine years has been 0.468 with a standard deviation of 0.019. Regressions between the sendout ratio and the percentage of split-year degree days in the heating season yield no significant results. See Response to Staff Information Request SR-1 E(2).

The Siting Council therefore accepts the Company's use of this ratio. Still, the Siting Council encourages the Company to monitor base load consumption patterns and to account for any changing patterns in the sendout forecast.

D. Projections of the Number of Customers

Fall River forecasts the addition of 1100 new residential heating customers between 1984/85 and 1988/89, which is an annual compound growth rate of less than one percent per year. Most of the new heating customers will be either new services or conversions of existing units owned by the Fall River Housing Authority ("FRHA") pursuant to a contract between the FRHA and Fall River (Response to Staff Information Request SR-2(C)). The Company expects that 50 residential non-heating customers will convert to gas heat each year. The Company bases its forecast on its judgements regarding historic growth patterns, gas and oil price trends, and contractual commitments from the FRHA. The Company states that the projected growth rate will "assume the approximate posture of the growth period prior to 1978" (Supplement, Section G-1, at 5). In addition, the Company presents evidence that the average cost of heating with gas during the 1984/85 winter will be competitive with the cost of heating with home heating oil (Response to Staff Information Request SR-2 B).

Fall River expects to add one industrial and about 36 commercial customers per year. These expectations are based on actual experience over the past five years and judgements about the Company's market area.

The Siting Council finds that Fall River's forecast of customer additions is reasonable. Further, the Siting Council compliments the Company on its documentation of its assumptions and judgements in this area, which appear to be appropriate to its growth posture. The Siting Council encourages the Company to continue to improve its documentation.

E. Commercial and Industrial Usage

The Company bases its forecast of annual commercial and industrial sendout on customer surveys and on historical average base and heating factors for each class. Fall River gathers information on industrial consumption trends through personal contacts with its industrial customers twice a month (Response to Staff Information Request SR-3). The Company forecasts that base and heating factors will stay constant over the forecast period because fluctuations in the historical data "do not appear to be indicative of any trend." (Supplement, Section G-3, at 2.) After forecasting total annual sendout from base and heating factors, degree-day data, and customer projections, the Company allocates sendout between the non-heating and heating seasons on the basis of the historical average percentage of annual sendout in each season over the previous ten years.

Fall River acknowledges that its industrial sendout has fluctuated wildly over the previous few years. The Company attributes the fluctuations to "split-class" use -- that is, decisions by industrial customers to switch some of their load from firm to interruptible status. The Company states that it will "continue to gather data pertinent to this situation." (Supplement, Section G-3, at 2).

The Siting Council is concerned with the lack of documentation of causal factors in the Company's forecast. Along with the Company's efforts to monitor the behavior of its split-class customers, the Siting Council believes that the forecast would be improved if the Company considered the impact of macroeconomic variables, as well as the impact of changes in customers' operating conditions and in its customer mix, on the base and heating factors and on the average seasonal percentages of total sendout. Further, the Siting Council believes that systematic and standardized surveys of commercial and industrial consumption would improve the quality of the Company's data for forecasting purposes.

Therefore, the Siting Council CONDITIONS its approval of this forecast methodology on the commencement of a program to improve Fall River's data and documentation regarding its sendout forecasts for the commercial and industrial classes. The Company shall meet with the Siting Council Staff to discuss the appropriateness of the current methodology, and to consider implementation of a standarized survey, SIC coding, consideration of economic variables, and other techniques as appropriate. This condition is affixed hereto as Condition 2.

F. Peak Day Methodology

Fall River has changed its peak day methodology since its previous forecast. The Company now calculates peak day sendout separately for each firm class by adding the daily base load factor for each class (in MMcf per day) to the product of the class's heating factor (in MMcf per degree day) and the peak day standard of 74 degree-days. Next, the Company sums the peak day sendouts for each class, then multiplies the total by 1.06 to correct for company use and unaccounted-for gas. This methodology replaces the Company's former practice of forecasting peak-day sendout on a system-wide basis.

The Siting Council notes that the new methodology explicitly accounts for forecasted changes in the contributions of different customer classes to peak day sendout. The new methodology depends less on aggregate trends than the Company's previous methodology. It also paves the way for the Company to monitor any changes in the heating factors of individual classes during periods of extremely cold weather.

The Siting Council approves the Company's new peak day methodology.

IV. RESOURCES AND FACILITIES

In the past, the Council has focused primarily on a gas company's ability to meet the requirements of its firm customers in reviewing that company's supply plan. A company's ability to meet firm peak day and normal and design weather requirements was the Council's major supply planning concern. In the past, the Council generally has not compared the costs of gas supply alternatives.

With a range of supply alternatives currently available at different prices, deliverability levels, and contract terms, the Council must now ensure a gas company's choice of supplies is consistent with the Council's mandate to ensure "a necessary energy supply with a minimum impact on the environment at the lowest possible cost." Mass. Gen. Laws Ann. ch. 164, sec. 69H (emphasis supplied).

The Council's task in observing its mandate is very complicated. The Council recognizes that a company's supply planning process is continuous, and that tradeoffs may exist between the reliability, cost and environmental impact of different supply sources. Further, the Council recognizes that a company's supply decisions are based on the information available and existing supply situation at the time the company's management makes the decisions. Thus, each company's supply plan will be different, and the Council will recognize the unique factors affecting the particular company under review. In the future, the Council will attempt to review each company's basis for selecting a supply alternative or the company's decisionmaking process to ensure that the company's decisions are based on projections founded on accurate historical information and projection methods.

In reviewing Fall River's current Supplement, the Council has examined, as before, the adequacy of Fall River's supplies to meet firm requirements under normal and design weather conditions, and peak day and cold snap conditions. The Council generally is satisfied that Fall River has sufficient supplies under these conditions. To the extent possible based on the existing record, the Council has reviewed Fall River's supply plan to determine whether the Company's plan ensures a necessary supply at the lowest possible cost. Fall River's filing itself contained little information to assist the Council in this latter task. Fall River responded, however, to the Council Staff's discovery on this issue. Nevertheless, the Council is unable to draw definite conclusions on whether Fall River's supply plan observes the least cost mandate consistent with providing reliable supplies. The Council's inability on this point derives both from the standards applied in past supply plan reviews occurring under different supply availability circumstances, and the level of information contained in the Supplement. The Council at this point does not in any way suggest an overall deficiency in the Company's supply planning. Rather, the Council is providing notice of the intended scope of future proceedings and of the type of information which the Council will require.

A. Overview

Fall River's resources and facilities are substantially the same as those described in the Council's most recent Fall River Decision.[9]

In summary, the Algonquin Gas Transmission Company ("Algonquin") provides the Company with pipeline gas under four separate contracts. Algonquin provides: firm gas service on a year-round-basis under the F-1 service agreement; firm winter service gas, available from November 16th through April 15th, under the WS-1 service agreement; underground storage and transportation service under the STB-1 service agreement; and SNG under the SNG-1 service agreement. Fall River supplements its pipeline gas supplies with liquified natural gas (LNG) from the Bay State Gas Company ("Bay State") and DOMAC, and propane from the Petrolane Northeast Gas Service Company ("Petrolane"). Table 2 summarizes the provisions of Fall River's existing gas supply contracts.

Since the last decision, Fall River has reduced its takes of SNG and has entered into a new propane contract. Also, Algonquin has two certificate applications pending before the Federal Energy Regulatory Commission ("FERC"). If approved, these proposals would significantly change Fall River's supply situation.

The Algonquin F-1 and WS-1, and the Bay State LNG agreements are scheduled for initial expiration within the forecast period. In its next Supplement, Fall River is requested to discuss in detail its plans for future contracts for each of these supplies.

B. F-4 Service Proposal

Algonquin has filed an application with FERC to provide Fall River with additional pipeline service on a 365-day basis under proposed Rate Schedules F-4 and F-4 Interim.[10] Algonquin and Fall River have entered into a Precedent Agreement dated January 16, 1985 covering this proposed service.

Algonquin proposes three stages for this service: 1) an interim interruptible service providing Fall River with an annual volumetric limitation ("AVL") of 3.5 MMcf immediately on approval by FERC; 2) a

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9. 10 DOMSC 165 (1983).

10. Algonquin Gas Transmission Co., FERC Docket No. CP84-654-001, "Amendment to Abbreviated Application for Certificates of Public Convenience and Necessity for (i) Limited Term Interruptible Sales Service and (ii) Long-Term Sales Service." Algonquin proposes to acquire the necessary supplies from Texas Eastern Transmission Corporation which has applied to FERC to acquire the supplies in the same stages from Columbia Gas Transmission Corporation. FERC Docket No. CP84-429-001.

Table 2

Fall River Gas Company

Current Gas Supply Agreements

Supplier	Contract	AVL/ACQ (MMcf)	MDQ (MMcf)	Cost[1] ($/Mcf)	Dates	Transportation
Algonquin	F-1	3,958.2	14.6	3.94	11/69-11/89	Algonquin Pipeline
Algonquin	WS-1	427.2	7.1	4.41	11/68-11/88	Algonquin Pipeline
Algonquin	SNG-1	302.5 108.5 93.0	[2]	12.72	12/73-4/85 4/85-4/86 4/86-4/87	Algonquin Pipeline
Algonquin	ST-1	180	1.8	7.94	4/80-4/2000	Algonquin Pipeline
DOMAC	Firm	435	-	5.47[3]	4/71-4/91	Truck
Bay State	Firm	263 788	-	5.47[3]	9/82-4/87 4/87-4/88	Truck
Bay State	Optional	87 262	-	5.47	9/82-4/86 4/87-4/88	Truck
Petrolane	Firm/Contract	275 125	-	8.29	7/80-4/85 4/85-4/90	Truck
Petrolane	Optional	41.2 18.7	-	8.29	7/80-4/85 4/85-4/90	Truck

1. Cost is based on the Company's Cost of Gas Adjustment filing for October, 1984. Response to Information Request SR-2A. This cost represents a 12-month rolling average as provided in CGAC filings.
2. SNG-1 MDQ varies from week to week. See Table 7 for actual MDQs.
3. The Cost of Gas Adjustment filing does not differentiate between the costs of DOMAC and Bay State LNG. Only the average cost for LNG is provided.

Source: Forecast, Table G-24. Response to Information Requests SR-2 & S-23 firm service development period beginning November 1, 1985, and ending on October 31, 1986, under which Fall River would have an MDQ of 1.7 MMcf and an AVL of 610 MMcf; 3) full firm service beginning November 1, 1986, under which Fall River would have an MDQ of 3.5 MMcf and an AVL of 1,277 MMcf. No construction of facilities is required for the interim service. Two short looping segments will be required by Algonquin in Massachusetts before full firm service can commence in 1986.

Although concerned about the Company's inability in responses to information requests to expound clearly the criteria and analysis used for evaluating the F-4 service proposal, the Council approves of Fall River's efforts to increase its firm pipeline resources. The Council notes, however, that given Fall River's low projected load growth rate, these increased pipeline supplies may require the Company to reevaluate its supplemental resource requirements. (See Section V.B, infra.)

C. Increased Storage Service

Algonquin has filed a certificate application with FERC in Docket No. CP84-712 which would provide Fall River with additional storage (95 MMcf per year) and transportation services (.95 MMcf per day) on a best-efforts basis. Algonquin and Fall River have signed a Precedent Agreement dated June 13, 1984, to enter into a service agreement for this storage service under a new Rate Schedule SS-III. To provide these services Algonquin would contract for transportation with the Texas Eastern Transmission Company, which in turn has proposed to purchase the underlying storage service from the Consolidated Gas Transmission Corporation. The proposed storage service delivery would be firm within the level of the F-1 and WS-1 MDQs. Thus, these additional resources would increase the Company's seasonal delivery capability, but the extent to which this supply could be counted on during peak day or under cold snap conditions is uncertain because delivery depends upon the availability of best efforts transportation services from three pipelines.[11] The Council requests Fall River to explain the status of this arrangement in detail in its next supplement. The discussion should include the status of regulatory proceedings, the cost and reliability of supply, and a comparison to other supply alternatives.

D. SNG Volume Reductions

Fall River has negotiated reductions in its contractual SNG volumes from 307.5 MMcf in the 1984-85 heating season to 108.5 MMcf in 1985-86 and 93.0 MMcf in 1986-87. This contract expires in April 1987. Algonquin has indicated that its "willingness to operate the facility after 1987 will depend on the seasonal volumes and production rates requested by the customers."[12] The Council commends Fall River for

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11. Fall River agrees stating that "the Company realizes that delivery of ... gas under these conditions [peak] is at best, questionable." Response to Information Request S-7.
12. In Re Algonquin SNG, Inc., No. 84-36, 12 DOMSC - (December 20, 1984).

reducing its SNG quantities, its highest cost resource, in light of the availability of other lower cost supplies.[13] Furthermore, the Council encourages Fall River to critically evaluate the costs and benefits of extending its SNG-1 contract in light of the potential availability of other lower cost supplies and the Company's ability to meet customers' design year and peak day requirements with the existing resources under contract when the SNG-1 contract expires. See Sections V.B. and V.C., infra. The Company is requested to discuss in its next filing its plans regarding SNG after the SNG-1 contract expires.

E. Petrolane Contract

Fall River has negotiated a new contract with Petrolane, effective April 1, 1985, which reduces the annual firm quantities of propane by 150 MMcf, from 275 MMcf to 125 MMcf. The new propane contract runs through the 1990 heating season and is supported by a lease of storage capacity in Providence, Rhode Island. In addition to these take-or-pay quantities, Fall River may request delivery of an additional 18.75 MMcf during any single 10-day period. These optional volumes, however, are available only on a best-efforts basis. The contract requires Petrolane to provide transportation of up to 9 truckloads per day (a total of approximately 6.4 MMcf) upon 24-hours notice from Fall River. Fall River owns 3 propane transports which are capable of hauling a total of 9 MMcf of propane per day from Petrolane's Providence, Rhode Island storage facility to the Company's facilities. (See Supplement at Cold Snap Analysis Section).

Under the new contract, the total propane quantity is available during the heating season, whereas under the previous contract 25 percent of the ACQ had to be taken in the non-heating season. These non-heating season volumes exceeded the Company's storage capacity of 37 MMcf. Consequently, propane was sent out during the non-heating season when other lower cost resources most likely were available.[14] The Council commends Fall River for eliminating its firm propane takes in the non-heating season and for reducing its total contract quantities, given the proposed increases in the Company's firm pipeline gas supplies.

F. Conservation Programs

The Siting Council evaluates conservation programs as a supply source on the same basis as other supply sources. The Siting Council considers these programs as part of its mandate of ensuring necessary

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13. For a discussion of how the SNG reductions affect the Company's sendout and adequacy of supply, see Section V.B., infra.
14. The actual storage capacity available for refill at the beginning of the non-heating season was generally much less than 37 MMcf, given Fall River's propane storage refill policy in which stored propane volumes are replaced as used to allow for a peak day.

gas supplies at the lowest possible cost with a minimum impact on the environment. Mass. Gen. Laws Ann. ch. 164, sec. 69H. Fall River's Supplement does not discuss conservation in terms of deliberate action being taken by a gas company to meet requirements which otherwise would be met from conventional supply sources (as opposed to "conservation" in the form of observated customer behavior). At a time when Fall River has supply alternatives and must plan for new contracts, the Siting Council believes conservation should receive concurrent attention. The Council also notes that there may be Company-sponsored conservation programs which, in conjunction with other supply resources, could reduce total supply costs below what it costs to supply customers without such conservation. The Siting Council requests Fall River to address such programs in its next Supplement, and the potential impact and cost-effectiveness on its supplies.

V. COMPARISON OF RESOURCES AND REQUIREMENTS

A. Normal Year

During a normal year Fall River must have sufficient resources to meet the requirements of its firm customers, refill storage before the start of each heating season, and meet fuel requirements for underground storage injection, withdrawal, and transportation. When possible, Fall River also supplies gas to its interruptible customers.

1. Non-Heating Season

Table 3 displays Fall River's requirements and resources during a normal year with the currently effective supply contracts, and the proposed SS-III storage service.

In the non-heating seasons, Fall River plans to take its full F-1 contract quantities and volumes in its WS-1 ACQ not taken during the previous heating season. Fall River also plans to take its full entitlement of DOMAC LNG, given the take-or-pay provision of the DOMAC contract. Given the close fit between the Company's seasonal totals of normal firm sendout and F-1 volumes, interruptible pipeline gas purchased from Algonquin provides Fall River with the volumes necessary to refill underground storage and to supply its interruptible customers.[15] The Company uses DOMAC LNG deliveries to refill its LNG storage tanks and to meet some of its temperature sensitive sendout. Fall River's LNG storage capacity (157 MMcf), however, is less than the non-heating season DOMAC LNG deliveries (210 MMcf).[16] Consequently, in a normal non-heating season some of this DOMAC LNG - the difference between the available LNG storage and LNG deliveries - is sent out. See Sections V.B, V.C. & V.D., infra.

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15. If the F-4 service proposal is approved by FERC, Fall River would be able to refill storage with the F-4 volumes, or with F-1 volumes that are no longer needed to meet firm requirements.

16. The actual storage capacity available for refill at the beginning of the non-heating season is expected to be roughly 120 MMcf to allow for a peak day late in the heating season.

Table 3

FALL RIVER GAS
COMPARISON OF RESOURCES AND REQUIREMENTS
NORMAL YEAR
(MMcf)

REQUIREMENTS	Non Heating 1984-85	Heating 1984-85	Non Heating 1985-86	Heating 1985-86	Non Heating 1986-87	Heating 1986-87	Non Heating 1987-88	Heating 1987-88	Non Heating 1988-89	Heating 1988-89
Normal firm sendout	1,928	3,693	1,942	3,714	1,946	3,721	1,950	3,725	1,952	3,729
Interruptibles	842		842		842		842		842	
Fuel reimbursement		7		10		15		13		13
Storage refill:										
Underground	150		135		275		275		206	
Propane		37		37		37		37		37
Liquefaction LNG	19		120		120		120		120	
TOTAL	2,939	3,737	3,039	3,761	3,183	3,773	3,187	3,775	3,120	3,779
RESOURCES										
AGT F-1	1,900	2,040	1,900	2,040	1,900	2,040	1,900	2,040	1,900	2,040
WS-1	70	357	70	357	70	357	70	357	70	357
SNG-1		303		109		93				
AGT Interruptible	684		859		1,003		1,007		940	
AGT Storage Return		135		180		275		206		206
LNG from storage		120		120		120		120		120
DOMAC LNG	210	225	210	225	210	225	210	225	210	225
Bay State LNG		263		263		263		665		669
Optional Bay State LNG		57		87		87				
Propane from storage		37		37		37		37		37
Firm propane purchases	75	200		125		125		125		125
Optional Propane				19		19				
Spot propane				199		132		0		0
TOTAL	2,939	3,737	3,039	3,761	3,183	3,773	3,187	3,775	3,120	3,779

Dispatch assumes 1) LNG and underground storage are filled to capacity in non-heating season.
2) Fall River attempts to take full volumes under firm contracts. Thereafter, Fall River will send out supplementals as required while attempting to minimize costs.
3) Propane volumes in storage will be used during the heating season and will be will be replaced as used.
4) Fall River will be able to renegotiate its LNG contract with Bay State Gas to balance load in 1987-88 and 1988-89.
5) Fall River is required to remove 75% of its storage gas in any contract year. Therefore, storage return resources must be at least 75% of the Company's storage capacity. Additional resources are dispatched on a cost basis.
6) Fall River's WS-1 contract is extended at least one year under current terms.

Sources: EFSC, Response to Information Request S-15, Fall River letter to EFSC dated February 11, 1985

As reflected on Table 4, if approved by FERC, the proposed F-4 volumes would significantly increase Fall River's non-heating season resources. Table 4 does not reflect any volumes under the proposed interim interruptible period. However, beginning in the 1986 non-heating season, the F-4 volumes would become available, with a substantial increase the following year. Fall River plans to use the F-4 gas to reduce its dependence on interruptible pipeline supplies to fill storage. Fall River also plans to use the remainder of the firm F-4 gas to increase sales to interruptible customers.

2. Heating Season

In order to meet firm requirements in the heating season through the 1986-87 heating season, as reflected in Table 3, Fall River plans to take its full contract quantities of F-1 and WS-1 pipeline gas, DOMAC and Bay State LNG, and the renegotiated volumes of SNG. If the F-4 volumes are not available by the 1985-86 heating season, Fall River projects it would be required to purchase 199 MMcf of propane on the spot market to make up for the reductions in the Company's SNG and propane contract quantities. In the 1986-87 heating season Fall River could reduce its spot propane purchase requirements to 132 MMcf if it receives all of its increased storage volumes.[17] In both years, spot propane purchase requirements would be reduced by purchasing F-4 gas which is scheduled to be available if FERC approves the F-4 service proposal. In the 1987-88 heating season, Fall River's firm Bay State LNG contract quantities increase by 525 MMcf to 788 MMcf, thereby eliminating the need for spot propane purchases and reducing dependence on Algonquin storage return volumes.[18]

The Council has several observations regarding Fall River's supply plan in the absence of the proposed F-4 deliveries. First, as indicated in Table 4, Fall River proposes to rely on increased storage return gas beginning in the 1986-87 heating season although, as described above, the SS-III service is proposed on a best efforts basis above the F-1 and WS-1 MDQ levels. Secondly, as a result of the 75-percent withdrawal requirement for the STB service, Fall River has indicated it would "elect to negotiate the Bay State contract to effect a decrease in the firm delivery in addition to the obvious waiver of the optional [LNG] in an amount to equal the required storage delivery quantity," for 1987-88 and 1988-89. See Response to Information Request S-15(a) and

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17. See Section V.B., <u>infra</u>, for further discussion of spot propane purchase requirements.

18. Under its STB-1 service agreement with Algonquin, Fall River is required to "remove or take delivery of at least 75% of its storage gas in an given contract year." Response to Information Request S-15. Therefore, Fall River would be required to take 75% of its storage volumes even though lower cost resources might be available.

Table 4

FALL RIVER GAS
COMPARISON OF RESOURCES AND REQUIREMENTS
NORMAL YEAR WITH F-4 INCREASES
(MMcf)

REQUIREMENTS	Non Heating 1984-85	Heating 1984-85	Non Heating 1985-86	Heating 1985-86	Non Heating 1986-87	Heating 1986-87	Non Heating 1987-88	Heating 1987-88	Non Heating 1988-89	Heating 1988-89
Normal firm sendout	1,928	3,693	1,942	3,714	1,946	3,721	1,950	3,725	1,952	3,729
Interruptibles	842		842		842		842		842	
Fuel reimbursement		7		10		13		13		
Storage refill:										
Underground	150		135		241		206		206	
Propane		37		37		37		37		37
Liquefaction										
LNG	19		120		120		120		120	
TOTAL	2,939	3,737	3,039	3,761	3,149	3,771	3,118	3,775	3,120	3,766
RESOURCES										
AGT F-1	1,900	2,040	1,900	2,040	1,900	1,948	1,900	2,040	1,900	2,040
F-4				252	358	397	749	397	749	397
WS-1	70	357	70	357	70	357	70	357	70	357
SNG-1		303		109		93				
AGT Interruptible	684		859		611		189		191	
AGT Storage Return		135		146		206		206		206
LNG from storage		120		120		120		120		120
DOMAC LNG	210	225	210	225	210	225	210	225	210	225
Bay State LNG		263		263		263		268		259
Optional Bay State LNG		57		87		0				
Propane from storage		37		37		37		37		37
Firm propane purchases	75	200		125		125		125		125
Optional Propane						0				
Spot propane		(0)		(0)		0		0		0
TOTAL	2,939	3,737	3,039	3,761	3,149	3,771	3,118	3,775	3,120	3,766

Dispatch assumes 1) LNG and underground storage are filled to capacity in non-heating season.
2) Fall River attempts to take full volumes under firm contracts. Thereafter, Fall River will send out supplementals as required while attempting to minimize costs.
3) Propane volumes in storage will be used during the heating season and will be will be replaced as used.
4) After the 1986-87 Heating Season Fall River will be able to reduce its Firm Bay State LNG quantities to balance load.
5) Fall River is required to remove 75% of its storage gas in any contract year. Therefore, storage return resources must be at least 75% of the Company's storage capacity. Additional resources are dispatched on a cost basis.
6) F-4 volumes are 100% take-or-pay.
7) Fall River's WS-1 contract is extended at least one year under current terms.

Sources: EFSC, Response to Information Request S-15, Fall River Co. letter to EFSC dated February 11,1985.

(b). The Council has minor reservations about Fall River's reliance on the full proposed SS-III storage return volumes. Accordingly, the Council requests the Company to discuss and justify this reliance in its next Supplement.

In the event the proposed F-4 volumes are forthcoming, Fall River would be able to eliminate any planned spot propane purchases. However, beginning in the 1987-88 heating season, when Fall River increases its takes of firm Bay State LNG, the Company's firm and take-or-pay resources would exceed the forecasted requirements of its firm customers, thereby requiring the Company to increase sales to interruptible customers or to reduce its F-1 takes to balance resources and requirements while it takes over 1,000 MMcf of firm LNG (from Bay State and DOMAC,) and 125 MMcf of propane.[19] See Section V.B., infra.

B. Design Year

In a design year Fall River must have resources in excess of those required in a normal year to meet the additional requirements of its temperature-sensitive customers. The design year resources and requirements are depicted on Tables 5 and 6.

In the non-heating season Fall River meets these additional firm requirements merely by reducing sales to interruptible customers. The Council notes, however, that if the full F-4 volumes become available in November 1986 as proposed, Fall River's firm resources in the 1987-88 and 1988-89 non-heating seasons would exceed its firm requirements by over 550 MMcf. Assuming the sales to interruptible customers are forthcoming as proposed, there appears to be little risk that these supplies would not be taken.

In the heating season the Company proposes to meet the additional requirements of its temperature-sensitive customers by increasing its takes of optional LNG from Bay State, Algonquin storage return, optional propane from Petrolane, and purchases of spot propane (in that order).[20]

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19. Fall River's proposed supplies for the 1987-88 heating season are as follows (MMcf):

AGT F-1	1908
F-4	529
WS	357
ST	206
Storage LNG	120
Bay State LNG	268
DOMAC LNG	225
Storage Propane	37
Purchased Propane	125

The Company's plan reflects a reduction in firm Bay State LNG, and a reduction in delivered F-1 gas. (Company letter dated February 11, 1985 to Council Staff.)

20. This assumes a least-cost dispatch.

Table 5

FALL RIVER GAS
COMPARISON OF RESOURCES AND REQUIREMENTS
DESIGN YEAR
(MMcf)

REQUIREMENTS	Non Heating 1984-85	Heating 1984-85	Non Heating 1985-86	Heating 1985-86	Non Heating 1986-87	Heating 1986-87	Non Heating 1987-88	Heating 1987-88	Non Heating 1988-89	Heating 1988-89
Design firm sendout	2,052	3,847	2,041	3,866	2,046	3,873	2,050	3,877	2,053	3,880
Interruptibles	842		689		589		585		651	
Fuel reimbursement		10		10		15		13		13
Storage refill:										
Underground	150		180		275		275		206	
Propane		37		37		37		37		37
Liquefaction										
LNG	19		120		120		120		120	
TOTAL	3,063	3,894	3,030	3,913	3,030	3,925	3,030	3,927	3,030	3,930
RESOURCES										
AGT F-1	1,900	2,040	1,900	2,040	1,900	2,040	1,900	2,040	1,900	2,040
WS-1	70	357	70	357	70	357	70	357	70	357
SNG-1		303		109		93				
AGT Interruptible	808		850		850		850		850	
AGT Storage Return	0	180		180		275		206		206
LNG from storage		120		120		120		120		120
DOMAC LNG	210	225	210	225	210	225	210	225	210	225
Bay State LNG		263		263		263		788		788
Optional Bay State LNG		87		87		87		29		32
Propane from storage		37		37		37		37		37
Firm propane purchases	75	200		125		125		125		125
Optional Propane		41		19		19				
Spot propane		41		351		284		0		0
TOTAL	3,063	3,894	3,030	3,913	3,030	3,925	3,030	3,927	3,030	3,930

Dispatch assumes
1) LNG and underground storage are filled to capacity in non-heating season.
2) Fall River attempts to take full volumes under firm contracts. Thereafter, Fall River will send out supplementals as required while attempting to minimize costs.
3) Propane volumes in storage will be used during the heating season and will be will be replaced as used.
4) Fall River will renegotiate their LNG contract with Bay State Gas to balance load in 1987-88 and 1988-89.
5) Fall River is required to remove 75% of its storage gas out of storage in a contract year. Therefore, storage return resources must be at least 75% provide the same volumes available in the 1987-88 heating season.patched on a cost basis.
6) Fall River's WS-1 contract is extended for at least one year under current terms.

Sources: EFSC, Response to Information Request S-15, Fall River letter to EFSC dated February 11, 1985

Table 6

FALL RIVER GAS
COMPARISON OF RESOURCES AND REQUIREMENTS
DESIGN YEAR WITH F-4 INCREASES
(MMcf)

REQUIREMENTS	Non Heating 1984-85	Heating 1984-85	Non Heating 1985-86	Heating 1985-86	Non Heating 1986-87	Heating 1986-87	Non Heating 1987-88	Heating 1987-88	Non Heating 1988-89	Heating 1988-89
Design firm sendout	2,052	3,847	2,041	3,866	2,046	3,873	2,050	3,877	2,053	3,880
Interruptibles	842		689		842		842		842	
Fuel reimbursement		10		10		13		13		13
Storage refill:										
Underground	150		180		275		206		206	
Propane		37		37		37		37		37
Liquefaction										
LNG	19		120		120		120		120	
TOTAL	3,063	3,894	3,030	3,913	3,283	3,923	3,218	3,927	3,221	3,930
RESOURCES										
AGT F-1	1,900	2,040	1,900	2,040	1,900	2,040	1,900	2,040	1,900	2,040
F-4				252	358	457	749	397	749	397
WS-1	70	357	70	357	70	357	70	357	70	357
SNG-1		303		109		93				
AGT Interruptible	808		850		745		289		292	
AGT Storage Return	0	180		180		206		206		206
LNG from storage		120		120		120		120		120
DOMAC LNG	210	225	210	225	210	225	210	225	210	225
Bay State LNG		263		263		263		420		423
Optional Bay State LNG		87		87						
Propane from storage		37		37		37		37		37
Firm propane purchases	75	200		125		125		125		125
Optional Propane		41		19						
Spot propane		41		99		0		0		0
TOTAL	3,063	3,894	3,030	3,913	3,283	3,923	3,218	3,927	3,221	3,930

Dispatch assumes 1) LNG and underground storage are filled to capacity in the non-heating season.
2) Fall River attempts to take full volumes under firm contracts. Thereafter, Fall River will send out supplementals as required while attempting to minimize costs.
3) Propane volumes in storage will be used during the heating season and will be will be replaced as used.
4) Fall River is required to remove 75% of its storage gas in any contract year. Therefore, storage return resources must be at least 75% of the Company's storage capacity. Additional resources are dispatched on a cost basis.
5) AGT F-4 volumes are 100% take-or-pay.
6) Fall River's WS-1 contract is extended for at least one year under current terms.

Sources: EFSC, Response to Information Request S-15, Fall River letter to EFSC dated February 11, 1985

As indicated on Table 5, in the 1985-86 design heating season, Fall River's spot propane purchase requirements would increase to 351 MMcf if F-4 volumes are not available. Although customarily concerned about the risks associated with spot market purchase requirements, the Council does not find this short-term reliance on spot propane unacceptable given the Company's relatively limited exposure and propane's significantly lower price than the resource - SNG-1 - it replaces.[21] Moreover, this spot purchase requirement could be reduced by increasing interruptible gas purchases in the shoulder months of the heating season and, if necessary, by increasing the Company's SNG-1 take.[22]

In accordance with a contract signed by Fall River in 1982, Fall River's Bay State LNG contract quantities increase by 525 MMcf to 788 MMcf in the 1987-88 heating season. This contract reduces the Company's reliance on spot propane purchases and Algonquin storage return volumes.[23] Yet, in June of 1984, Fall River signed a precedent agreement for increased underground storage and ancillary transportation capacity from 1986-87 through 2005-2006. The Council is unable on the present record to determine how Fall River evaluated each of these supply proposals.

If F-4 volumes become available in the 1987-88 heating season, as proposed, these increases in firm pipeline gas will coincide with Fall River's increased takes of Bay State LNG, and the Company's combined firm and take-or-pay resources would exceed the forecasted requirements of its firm customers. To balance resources and requirements the Company would have to either reduce takes of low cost pipeline volumes - F-1 or F-4 - while taking 1,000 MMcf of LNG and 150 MMcf of propane, as required by its take-or-pay contracts, or add interruptible loads during the heating season.[24] (See Table 6.). As stated above, the Council has not been presented with sufficient information to assess the Company's supply planning process with regard to the acquisition of the F-4 supplies. Accordingly, the Council ORDERS Fall River to provide in its next filing a detailed plan for balancing its resources and requirements

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21. Fall River's Cost of Gas Adjustment Clause filing for October, 1984, indicated that the charge for SNG was $12.72/MMcf and $8.29/MMcf for propane. A report recently commissioned by the Council confirmed that propane is likely to be available on the spot market during peak periods. J. Makowski Assoc., An Analysis of the Massachusetts Propane Market, 1984. This report is cited as general reference and does not reflect a finding of fact in this particular proceeding.
22. See Algonquin SNG, Inc., No. 84-36, 12 DOMSC (December 20, 1984).
23. See footnote 18, supra.
24. The Council generally endorses the goal of increasing firm pipeline supplies. However, the Company did not present to the Council the planning process it used to minimize cost. Fall River indicated that it could renegotiate its Bay State LNG contract to reduce contractual volumes to better balance load. Response to Information Request, S-15.

in both the non-heating and heating season if the F-4 volumes are approved. The Company should demonstrate that this plan provides an adequate supply of gas at the lowest possible cost.

In last year's decision, the Council, in its discussion on design year, requested the Company to present a contingency plan for LNG. The Council reimposes this Condition, herein.

Fall River clearly has sufficient resources in normal and design years to meet its customers' firm requirements on a seasonal basis. However, the Council is concerned about Fall River's failure to demonstrate to the Council the planning process used by the Company to evaluate the F-4 service.[25] Therefore, to ensure that future supplies are properly evaluated in terms of both need and cost, the Council ORDERS the Company to explain and justify in its next filing with the Council the criteria and processes it uses to evaluate new supplies and service contracts. Fall River's review process for evaluating supplies should be demonstrated to be both systematic and reviewable. Furthermore, the Company is on notice that future forecasts should demonstrate the basis for new gas supply decisions by fully evaluating the costs of new gas supplies and comparing these costs with alternatives. The Council Staff is available to assist Fall River in complying with both those CONDITIONS.

C. Peak Day

Fall River must have sufficient daily pipeline supplies, supplemental storage and sendout facilities to meet the requirements of its firm customers on a peak day. Table 7 illustrates the Company's projected peak day sendout capability and requirements for each year of the forecast.

As discussed earlier (Section IV. B), a proposal is pending for an increase in Fall River's firm service MDQ (3.5 MMcf). This increase in pipeline peak day resources would be offset by the reduction in SNG-1 volumes from Algonquin. In the 1985-86 heating season Fall River's SNG-1 takes on a peak day decrease by approximately 2 MMcf per day.[26] This reduction in peak day resources, however, does not threaten Fall

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25. The Council asked Fall River to "describe the Company's decision-making process including any cost strategy in arriving at the additional [F-4] quantities to be purchased from Algonquin... [including] whether the Company used gas sendout scenarios based on existing contracts in determining the amount." (Information Request S-24.) Fall River responded: "The Company decision making process in arriving at the additional F-4 volumes to be purchased from Algonquin involved cost strategy in relation to the gas sendout scenarios over the period." Response to Information Request S-24.
26. The actual SNG volumes available from Algonquin during the heating season vary from week-to-week and in some instances day-by-day. (See Table 7.)

River's ability to meet peak day requirements. Even if SNG were not available in the 1987-88 heating season, Fall River's resources would exceed requirements by over 18 percent. Further, even if the proposed F-4 MDQ is not approved, the Company would have sufficient resources to meet peak day requirements. Therefore, the Council finds that Fall River's peak day resources and sendout facilities are sufficient to meet firm peak day requirements.

D. Cold Snap

Fall River must have sufficient resources to meet the requirements of firm customers in the event of a cold snap. The Council regards as crucial a company's plans to meet a cold snap. A "cold snap" is defined by the Council as a period of peak or near peak weather conditions.

The Council encourages gas companies to develop their own company-specific cold snap standard, based on the company's supply situation and historic weather conditions. In its previous Decision, the Council ordered Fall River:

> to present a cold snap standard that it considers appropriate (for example, a standard based on a hypothetical cold snap similar to the one experienced in December 1980 and January 1981). The analysis should clearly indicate the roles of propane, LNG, and trucking to meet daily sendout requirements during the cold snap.[27]

The Company has adopted a cold snap standard of an extended period of peak days. Additionally, the Company has conducted a cold snap analysis, which included a review of the Company's propane and LNG daily transportation capabilities.

Fall River owns three propane trucks which are able to transport roughly 9,000 Mcf per shift from Petrolane's storage facilities in Providence. With full storage and the Company's trailers hauling 9,000 Mcf per day, Fall River would be able to send out propane at its maximum capacity for twelve days. If there was no transportation service but with full storage, Fall River would be able to sendout propane at maximum rated capacity for three days.

Fall River also owns two LNG transports which can haul 5,100 MMcf per day from the DOMAC storage facility in Everett. Thus, vaporing at the maximum rate with one vaporizer, Fall River's LNG storage volumes drop by 5220 Mcf per day. With full storage, Fall River would be able to vaporize at full capacity with one vaporizer for thirty days. With a full tank and no transportation, Fall River would be able to run one vaporizer at capacity for fifteen days. Even at the close of a design

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27. 10 DOMSC 165, 179 (1984).

Table 7

·Fall River Gas Company
Peak Day Resources and Requirements

(MMcf)

RESOURCES	1984-85	1985-86	1986-87	1988-88	1988-89
Algonquin					
F-1	14.6	14.6	14.6	14.6	14.6
F-4	-	1.7	3.5	3.5	3.5
WS-1	7.1	7.1	7.1	7.1	7.1
SNG-1[1]					
STB-1[2]	1.87	1.87	1.87	1.87	1.87
Supplementals					
LNG	20.0	20.0	20.0	20.0	20.0
Propane	12.0	12.0	12.0	12.0	12.0
TOTAL RESOURCES	55.57	57.27	59.07	59.07	59.07
REQUIREMENTS	48.7	49.1	49.2	49.2	49.2

1. SNG-1 MDQs vary from week to week. See Table 8, infra.

2. The daily storage demand is 2.0 MMcf. The difference between the daily storage quantity and the firm deliverable portion is .13 MMcf which represents fuel charges.

Source: Forecast, Table G-23

Table 8
Fall River Gas Company's
Algonquin SNG Volumes

(MMcf/Day)

	1984-85 Heating Season	1985-86 Heating Season	1986-87 Heating Season
Dec. 10-31	3.0	1.0	1.0
Jan. 1-30	5.5	2.5	2.0
Jan. 31	4.5	2.5	2.0
Feb. 1-15	3.5	1.0	1.0
Feb. 16-28	2.5	0	0
Total Deliveries	302.5	108.5	93.0

Source: Algonquin SNG Rate Schedule

heating season with a LNG inventory of 37 MMcf and no transportation, Fall River would be able to operate one vaporizer at capacity for three days. Therefore, the Council finds that Fall River's storage and transportation capacity provide the Company with sufficient resources to meet the requirements of a cold snap throughout the forecast period.

The Council notes, however, that Fall River's cold snap standard is the most stringent standard possible. Fall River selected "a series of peak days for a cold snap in order to stage a scenario for what would be the most stringent set of circumstances that could possibly occur." Response to Information Request S-17.

An overly stringent standard is not problematic if used solely to demonstrate the adequacy of the Company's resources. However, an appropriate planning standard - whether for a cold snap, peak day, design year, or normal year - should balance the benefits of a reduced risk of a supply shortfall with the costs of the additional resources and supplies.[28] Fall River's cold snap standard - a series of peak days - appears to be too stringent. The Council notes that although using a more stringent standard than is "reasonably expected to occur" reduces the risks of a supply shortfall, it can lead also to a redundancy in resources and facilities which provides few additional reliability benefits while possibly increasing system costs. The Company's response to a Siting Council information request suggests that Fall River uses this cold snap standard to determine the adequacy of the Company's resources to meet cold snap conditions: "the circumstances cited were used as much for the Company's information as they were to supply the Council with an answer to their request." Response to Information Request S-17. In last year's decision, the Council specifically suggested that a different standard based on the degree days experienced in a recent cold snap might be more appropriate. 10 DOMSC at 179. In the present Supplement, Fall River has presented a cold snap standard and described the role of supplemental supplies. Fall River, however, has not adopted a cold snap standard which is based on realistic weather conditions. Therefore, the Council Orders the Company to meet with the Council Staff to discuss development by the Company of an appropriate standard, and to present that standard in the next Supplement.

VI. DECISION AND ORDER

The Council hereby Approves Conditionally the Third Supplement to the Second Long-Range Forecast of Gas Requirements and Resources of the Fall River Gas Company. The Company is requested to meet with Council Staff within 60 days to discuss compliance with the following conditions. In its next supplement, to be filed with the Council on July 1, 1985, the Council hereby ORDERS Fall River to:

1. Commence data collection efforts to support the selection of trends in base and heating factors in future forecasts.

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28. This assumes that the additional gas supplies are purchased only to ensure an adequate supply and not to add load.

2. Commence a program to improve data and documentation for the commercial and industrial classes.

3. Provide in its next filing the process and criteria used to evaluate new supplies and service contracts. Additionally, the Company shall provide in its next filing a detailed plan for balancing its resources and requirements in both the non-heating and heating seasons, if the F-4 volumes are approved. This plan should state Fall River's assumption regarding the future price of supplementals and the optimal levels of each supplemental so that firm customers requirements are met with an adequate supply at the lowest possible cost.

4. Develop an appropriate cold snap standard reflecting a realistic cold snap weather pattern and present it in the next Supplement. The standard should reflect the Council's concerns expressed herein.

5. Present in its next Supplement, an LNG contingency plan. The plan shall contain a statement concerning the reliability of DOMAC deliveries and a standard for determining when replacement supplies are needed and possible sources of those replacements.

James G. White, Jr.

James G. White, Jr.

APPROVED UNANIMOUSLY by the Energy Facilities Siting Council on March 14, 1985, by those members and designees present and voting: Chairperson Sharon M. Pollard (Secretary of Energy Resources); Joellen D'Esti (for Evelyn Murphy, Secretary of Economic and Manpower Affairs); Joseph Joyce (Public Labor Member); Dennis LaCroix (Public Gas Member); Robert Gillette (Public Environmental Member).

15 March 1985
Date

Sharon M. Pollard

Sharon M. Pollard
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Cambridge Electric Light, Canal Electric, and Common-wealth Electric Companies for Approval of the Combined First and Second Supplements to the Second Long-Range Forecast of Electric Power Needs and Requirements	)	EFSC No. 84-4

FINAL DECISION

James G. White, Jr.
Hearing Officer

On the Decision:

George H. Aronson

The Energy Facilities Siting Council ("Siting Council") hereby APPROVES, in part, and REJECTS, in part, subject to Conditions, the Petition of Cambridge Electric Light, Canal Electric, and Commonwealth Electric Companies for Approval of the Combined First and Second Supplements to the Second Long-Range Forecast of Electric Power Needs and Requirements ("the Forecast"). As discussed herein, the Siting Council APPROVES unconditionally the demand portion of the Forecast, and REJECTS and imposes four CONDITIONS on the supply portion.

I. INTRODUCTION AND HISTORY OF THE PROCEEDINGS

A. Description of the Companies

The Cambridge Electric Light Company ("Cambridge"), the Canal Electric Company ("Canal") and the Commonwealth Electric Company ("Commonwealth") are subsidiaries of the Commonwealth Energy System ("COM/Electric", or "the System").

Cambridge produces, sells and distributes electricity to approximately 40,000 retail customers in the City of Cambridge, and sells power for resale to the town of Belmont. In addition, Cambridge sells steam from its electric generating plants to an affiliated company, COM/Energy Steam Company. Cambridge had retail sales in 1983 of approximately 902,300 megawatt-hours ("MWH"), with a summer peak demand (excluding Belmont) of 189 megawatts ("MW") (Forecast at I.1.1 and I.2.3).

Commonwealth produces, sells and distributes electricity to approximately 233,000 retail customers in forty communities in Southern Massachusetts, including the greater Plymouth and New Bedford areas, Cape Cod, and Martha's Vineyard. Year-round population is approximately 475,000, with summer totals being considerably higher. In 1983, Commonwealth had retail sales of 2,426,354 MWH, with a winter peak demand of 491 MW (Forecast at I.1.2).

Together, the two companies had retail sales in 1983 of 3,329,000 MWH and a coincident winter peak load (excluding Belmont) of 632 MW. Commonwealth's load comprised 73 percent of the System's retail sales and approximately 74 percent of the coincident winter peak demand in 1983 (Forecast at I.2.36-37 and I.5.11-13).

Canal generates electricity at two facilities located on the Cape Cod Canal in Sandwich, Massachusetts. Canal Unit No. 1, rated at 568 MW, is an oil-burning base-loaded unit; Canal Unit No. 2, rated at 584 MW, is an oil-burning cycling unit. Canal sells the output of Unit No. 1 to five utilities, including Cambridge and Commonwealth. Ownership of Unit No. 2 is evenly divided between Canal and Montaup Electric Company, an unaffiliated company. Canal's other major assets are the System's entitlements in Seabrook Units 1 and 2, amounting to 81 MW or 3.52 percent of each unit. Canal has no retail sales (Forecast at I.1.1).

Each of the retail companies produces its own demand forecast, which is filed with the Siting Council along with a joint forecast of total energy demand and coincident peak demand. Supply information, filed with the Siting Council by all three companies, is reviewed for the COM/Electric System as a whole, consistent with the System's treatment by the New England Power Pool.

The System does not propose to construct any new facilities in the instant filing.

B. History of the Proceedings

The System filed its Forecast on May 1, 1984. The System provided notice of this proceeding to the public by publication and posting in accordance with the directions of the Hearing Officer. The Siting Council received no intervention petitions. Thus, formal hearings were not held. Instead, the record in this case was compiled through a written discovery process. The System submitted responses to Information Requests prepared by the Siting Council Staff. Technical Sessions were held to clarify the scope of the discovery process.

The record in this case consists of the original Forecast filing, the System's written answers to staff Information Requests, and associated written correspondence. The Tentative Decision was prepared based on the information in the record, the applicable Siting Council statutes and regulations, and precedents in previous Final Decisions. In addition, the Siting Council has advised counsel for COM/Electric that notice has been taken of the April 4, 1985, decision by the Massachusetts Department of Public Utilities in the "generic" Seabrook 1 proceeding, DPU No. 84-152.

II. REVIEW OF THE DEMAND FORECAST

A. Scope 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" (Mass. Gen. Laws Ann. ch. 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" (Mass. Gen. Laws Ann. ch. 164, sec. 69J). The Siting Council applies three standards of review: the reviewability of the forecast (whether the results can be evaluated and duplicated by another person, given the same level of technical resources and expertise); its appropriateness (whether it is technically suitable to the size and nature of the utility's system); and its reliability (whether it instills confidence that its data, assumptions and judgements produce a forecast of what is most likely to occur). In Re Northeast Utilities, 11 DOMSC 1, 4 (1984); In Re Boston Edison, 10 DOMSC 203, 209 (1984).

The Siting Council finds that the System's demand forecasts are reviewable. The System is to be commended for its complete documentation of the methodologies of both the Cambridge and Commonwealth demand forecasts, and its cooperation during the discovery process. Such documentation allows the Siting Council to conduct its review in depth, thereby allowing the review process to serve as a vehicle for forecast refinement and improvement. Indeed, the System has set a standard of reviewability that other electric companies in the Commonwealth would do well to emulate.

The Siting Council analyzed the appropriateness and reliability of the System's demand forecast extensively in its previous Decision on the System, In Re COM/Electric, 9 DOMSC 222 (1983). In that Decision, the Siting Council approved Cambridge's demand forecast without Conditions, though the text of the Decision contained numerous recommendations for future refinements and changes in the methodology. The Siting Council approved Commonwealth's demand forecast subject to four Conditions, as listed below, 9 DOMSC at 264:

1. That the Companies conduct a sensitivity analysis of the Commonwealth model, and submit the results of this analysis with their next filing.

2. That the Companies perform an in-depth literature search on residential appliance connected loads and use profiles, and demonstrate the applicability of the NEPOOL data for the Commonwealth service area in light of the research, or address appropriate changes in the residential data base with their next filing.

3. That the Companies perform an in-depth literature search on commercial kilowatthour-use-per-employee estimates, by end use, and demonstrate the applicability of the NEPOOL data for

the Commonwealth service area in light of the research or address appropriate changes in the commercial data base with their next filing.

4. That the Companies perform an aggregate price elasticity study, by customer class, for the Commonwealth service area. The study should include electricity prices, prices of substitute fuels, and income at a minimum. The Companies should attempt to demonstrate the applicability, or lack thereof, of the NEPOOL elasticities in light of this study, and submit these results with their next filing.

The text of the Siting Council's previous Decision also contained numerous recommendations for future refinements and changes in Commonwealth's methodology.

The current review evaluates the appropriateness and reliability of the current demand forecast methodologies as modified by the responses to the foregoing Conditions, by the responses to suggestions in the text of the previous Decision, and by methodological refinements initiated by Commonwealth and Cambridge. This Decision presents the results of the two forecasts, then reviews the forecast methodologies of the two companies separately.

B. Forecast Results

Table 1 summarizes the results of the Commonwealth and Cambridge demand forecasts for 1984-93 as presented in the initial forecast filing.

Cambridge projects that its retail sales will increase at an annual compound rate of 1.63 percent per year over the forecast period. Sales to the commercial sector (including municipal sales and street lighting) comprise approximately 73 percent of its total sales. Cambridge projects that commercial sales will grow at an annual compound rate of 1.81 percent, faster than any other sector. Sales to the industrial sector, which comprise approximately 15.3 percent of total sales, are projected to grow at 1.74 percent per year, and sales to the residential sector, which comprise approximately 12 percent of total sales, are projected to grow at only 0.34 percent per year. Cambridge projects that it will continue to experience its peak load in the summer. Summer peak load is projected to grow at 1.56 percent annually; winter peak load, at 1.03 percent annually.

Commonwealth projects that its retail sales will grow at a compound rate of 2.54 percent per year over the forecast period. Sales to residential customers comprise approximately 49 percent of Commonwealth's total sales; sales to commercial customers, approximately 37 percent; and sales to industrial customers, approximately 14 percent. Commonwealth projects that industrial sales will grow at 3.03 percent per year, faster than any other sector. Both residential sales and commercial sales are projected to grow at approximately 2.5 percent per year. Commonwealth projects that it will continue to experience its peak load in the winter, though summer peak growth (2.75 percent per year) is projected to be higher than winter peak growth (2.55 percent per year).

For the System as a whole (excluding sales to Belmont), sales are projected to grow at 2.3 percent annually, the System's summer peak is projected to grow at 2.6 percent annually, and the System's winter peak is projected to grow at 2.2 percent annually.

TABLE 1
Demand Forecast Summary, 1983-93
Commonwealth and Cambridge Electric Companies

	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
Commonwealth	Actual	Forecast									
Annual sales (000 MWH)	2426.3	2476.7	2577.7	2665.2	2744.0	2807.8	2875.4	2941.1	3000.9	3054.4	3103.8
Residential	1164.4	1208.0	1247.0	1279.0	1317.0	1355.0	1391.0	1428.0	1456.0	1477.0	1498.0
Commercial	914.8	919.6	967.0	1010.1	1039.2	1056.2	1077.5	1094.5	1113.5	1132.6	1149.0
Industrial	347.1	349.1	363.7	376.1	387.8	396.6	406.9	418.6	431.4	444.8	456.8
Peak demand (MW)											
Summer	468.0	477.0	497.0	514.0	531.0	545.0	561.0	575.0	588.0	599.0	609.0
Winter	491.0	499.0	518.0	534.0	548.0	563.0	577.0	591.0	602.0	613.0	626.0
Cambridge											
Annual sales (000 MWH)	902.3	926.4	972.4	985.2	996.8	1010.9	1027.9	1045.2	1061.7	1066.8	1071.1
Residential	115.3	114.1	116.2	116.5	116.5	116.6	117.1	117.3	117.7	117.7	117.6
Commercial	646.3	670.9	707.4	717.6	725.8	737.3	751.7	766.6	780.6	784.8	788.3
Industrial	140.7	141.4	148.8	151.1	154.5	157.0	159.1	161.3	163.4	164.3	165.2
Peak demand (MW)											
Summer	189.0	194.0	203.0	205.0	208.0	211.0	215.0	219.0	222.0	223.0	223.0
Winter	149.0	155.0	156.0	158.0	160.0	163.0	166.0	167.0	168.0	169.0	170.0

Source: Forecast, at I.2.3 and I.4.5.

C. Analysis of the Cambridge Demand Forecast

1. Overview of the Methodology

The nature of the Cambridge service territory poses special challenges for the demand forecaster. As a fully developed urban area, Cambridge has a comparatively stable residential population, and a large commercial sector. Much of the load growth occurs in discrete chunks, corresponding to individual development projects. Cambridge is an integral part of the Greater Boston area, which raises substantial questions regarding the appropriateness of methods that model Cambridge as a self-contained economic region. Moreover, the city is sufficiently small, and several customers sufficiently large, that city-wide sales are sensitive to the level of sales to individual customers. Indeed, the four largest commercial customers in Cambridge account for almost 33 percent of total demand (45 percent of total commercial sales), and eighteen large industrial customers account for an additional 13 percent (85 percent of total industrial demand sales) (Forecast at I.2.9, I.2.14, I.2.35).

Under these circumstances, it is not surprising that Cambridge relies heavily on surveys of the loads of individual large customers and information on specific new development projects in producing its demand forecast. Cambridge supplements its surveys and development information with econometric modeling and analysis of historical data.

2. The Commercial Sector

Cambridge separates its commercial class into three components: surveyed customer sales, step loads, and baseline sales.

Cambridge forecasts sales to its four largest customers by surveying them for these customers' own internal forecasts of electricity consumption over the upcoming ten years. To this survey information, Cambridge adds step loads corresponding to the new development projects listed in its Development Project Information System ("DPIS"). The DPIS data consist of estimates of the full electricity load of individual projects multiplied by the probability that the project will be completed as anticipated. Finally, Cambridge forecasts baseline sales as the product of the currently existing number of commercial customers (excluding the four largest) and the average use per baseline customer. Average use per customer is forecasted econometrically as a function of the real price of electricity and time using ten years of time-series data. (Forecast at I.2.8-9, I.2.12).

The Siting Council notes that Cambridge's methods for forecasting step loads and surveying customer sales have not changed substantially since its previous filing. However, Cambridge has changed its methodology for forecasting baseline commercial sales.

In its previous forecast, Cambridge forecasted baseline commercial sales as an econometric function of Massachusetts commercial sales, weighted by a correction factor to alleviate the affects of double-counting. The Siting Council criticized this methodology, and found that Cambridge had not adequately supported its use of the correction factor, 9 DOMSC at 243 (1983).

Cambridge's new method for forecasting baseline commercial sales alleviates several of the Siting Council's concerns. By forecasting average use per customer for a given set of customers (instead of total baseline sales), Cambridge avoids the double-counting problem, and, hence, has no need for the correction factor that the Siting Council criticized.[1] The new specification treats price and saturation effects explicitly; it avoids reliance on the NEPOOL commercial data base and on the stability of relationships between the economies of Massachusetts and Cambridge. Thus, the Siting Council is satisfied that Cambridge has improved this aspect of its commercial demand forecast.

The Siting Council notes that the reliability of Cambridge's forecast of commercial demand depends heavily on the reliability of the internal demand forecasts provided by the four large commercial customers that comprise 45 percent of Cambridge's commercial load.

In the previous Decision, the Siting Council asked Cambridge to compare actual sales to individual large industrial customers with the customers' own forecasts of sales in order to evaluate the reliability of their internally generated forecasts (9 DOMSC 222, 244 (1983); see section II.C.3, infra). The Siting Council believes it appropriate for Cambridge to evaluate the forecasting performance of its large commercial customers in similar fashion.

Indeed, Cambridge has already begun to examine the performance record of these customers. Cambridge states that

> ... 3 years of data is not sufficient to conduct a performance evaluation. However, preliminary analysis does indicate a possible under forecasting trend that the Company is planning to discuss with these customers. Response to Staff Information Request D-37.F.

The Siting Council is pleased that Cambridge has begun this performance evaluation, and requests that Cambridge document the results of its evaluation in its next forecast.

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1 The "YEAR" variable is essentially a proxy for the increasing saturation of electrical equipment into existing floor space. Response to Staff Information Request D-37.B.

Regarding the reliability of the DPIS data, the System states that it

> ... has attempted to evaluate the accuracy of load information, but difficulties have arisen.... As time and priorities permit, future attempts will be made... . Response to Staff Information Request D-37.G.

The Siting Council recognizes the difficulty of forecasting the outcomes of individual development projects. Still, the Siting Council notes that the DPIS data show load growth of 88,455 MWH by 1993, which is 75 percent of Cambridge's forecasted growth of 117,900 MWH in commercial demand over the forecast period (Forecast at I.2.13 and I.2.34). The Siting Council believes that assessment of the reliability of the DPIS data base is critical for the assessment of the reliability of Cambridge's commercial demand forecast. To this end, the Siting Council requests that Cambridge begin to compare the actual demand from new commercial developments to the demand forecasted by DPIS. The Siting Council further expects Cambridge to document its performance evaluation of the DPIS forecast in its next forecast in a manner similar to its evaluation of large customer forecasts.

3. The Industrial Sector

Cambridge's methodology for forecasting industrial sales in the instant filing is substantially identical to that of its previous filing. Cambridge received forecasts of consumption (assumed to account for estimated self-generation) over the forecast period from nineteen large customers accounting for 85 percent of industrial class sales. Historic sales to these large customers were regressed against total industrial sales to determine a relationship. Cambridge used this relationship to forecast baseline industrial sales from the survey data, then added expected loads for several industrial step load additions from the DPIS data base to produce the full industrial forecast (Forecast at I.2.9; Response to Staff Information Request D-38.D).

The Siting Council notes that the reliability of the methodology described above depends on three factors: the stability of the relationship between the total sales of surveyed customers and the total sales of all existing customers; the reliability of the load forecasts provided by the large industrial customers; and the reliability of the DPIS data on load additions.

During the course of this proceeding, Cambridge reported its intent to revise its methodology for forecasting total sales to existing industrial customers. Instead of using the historical relationship between surveyed and class-wide sales, Cambridge states that it now forecasts sales to unsurveyed existing customers based on the historic rate of decline of sales to these customers (Response to Staff Information Request D-38.B).

The Siting Council is pleased with this revision. The number of customers that have responded to Cambridge's load survey has varied over the last few forecasts, as has the ratio of surveyed customer sales to class-wide sales (Forecast at I.2.7 and I.2.9). The method avoids reliance on a ratio that may change unpredictably over time; it also avoids reliance on the accuracy of forecasts from surveyed customers to forecast consumption by unsurveyed customers. The Siting Council requests Cambridge to document the equation that it uses to forecast sales to unsurveyed customers in its next forecast.

Of more concern is the reliability of the forecasts of their own future consumption that the large customers provide to Cambridge in response to the survey. At the Siting Council's request, Cambridge provided in its initial filing a performance evaluation of the responses to its 1982 survey of large industrial customer loads. Specifically, Cambridge provided data for 1982 and 1983 on actual sales in MWH, the customer's own forecast of sales in MWH, and the variance between the two for the fifteen customers that responded to its 1982 industrial demand survey (Forecast at I.2.7).

The results of the performance evaluation lend some cause for concern. True, actual sales differed from forecast sales by only 2.1 percent in 1982, and 1.8 percent in 1983, but several customers differed by as much as 10 percent, and one customer, by 300 percent[2] (Id.). Generally, the Siting Council agrees with Cambridge's statement that it does not yet have sufficient data to conduct a valid performance evaluation (Response to Staff Information Request D-37F).

Therefore, Siting Council encourages Cambridge to continue to monitor the forecasting performance of its surveyed customers and to identify and correct for significant errors by individual large customers as appropriate. The Siting Council expects Cambridge to continue to report the results of its evaluations in future forecasts. Further, the Siting Council encourages Cambridge to monitor the amount of self-generation by its large industrial customers, and to account for it in future forecasts.

Regarding the reliability of the DPIS data, Cambridge makes the same statement about industrial load additions as it did for commercial load additions; namely, that it has attempted to evaluate the accuracy of the information, but difficulties have arisen (Response to Staff Information Request D-38C).

The Siting Council notes that Cambridge's forecast of 4875 MWH of large industrial step loads comprises approximately 38 percent of total industrial load growth over the forecast period, but only 3.3 percent of total growth in demand (Forecast, at I.2.34; Response to Staff Information Request D-8). For growth of this magnitude, the Siting Council believes that the DPIS data should be evaluated by comparing actual demand to forecasted demand in the same way that Cambridge

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2 The Siting Council notes that the reported error statistics are mean errors, not mean square errors. Thus, large errors by individual customers in different directions cancel each other. Cambridge may want to consider reporting mean square errors in future forecasts.

monitors the load forecasts of its large industrial customers. The Siting Council expects Cambridge to document its performance evaluation of the DPIS data in its next filing.

4. The Residential Sector

Cambridge has changed significantly its methodology for forecasting residential sales. Instead of holding class-wide usage constant over the forecast period, Cambridge forecasts residential sales as the product of the number of customers and the average use per customer. Average use per customer and the number of customers are forecasted separately for heating customers and non-heating customers. Cambridge forecasts the number of customers as the existing number of customers corrected for known customer additions and master meter conversions. Average use per customer is forecasted using econometrics. For the residential heating class, average use is a function of electricity price and the number of degree days; for the residential non-heating class, average use is a function of electricity price and the average use lagged one year.

The Siting Council notes that Cambridge has improved the conceptual basis for its forecast in two ways: by separating heating customers from non-heating customers; and by separating the number of customers from average use per customer. The econometric specifications performed well, despite the lack of data on residential electric heating demand.[3]

The Siting Council's confidence in the predictive power of these equations is somewhat reduced by the lack of data on residential heating demand, and by the fact that lagged average use explains 93 percent of the variation in the non-heating regression (Response to Staff Informtion Request D-36.C.3).

Nevertheless, because of the comparatively small size of the residential sector (about 10 percent of total energy output requirements by 1993), the stability in the rate of historical sales (see 9 DOMSC at 240 (1983); Forecast at I.4.32), and the small amount of residential load growth (2,300 MWH by 1993, compared to 117,900 MWH for the commercial sector), the Siting Council finds that the present methodology is appropriate to the size and nature of Cambridge's residential sector. The Siting Council encourages Cambridge to continue to test alternative specifications for its econometric equations as further data become available.

The Siting Council's previous Decision urged Cambridge to perform a residential appliance saturation survey, 9 DOMSC at 241 (1983).

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3 Cambridge did not separate heating customers from non-heating customers in its records until 1976. Still, both the heating and non-heating regression equations explained over 95 percent of the variation in the dependent variable, and all coefficients were statistically significant, Forecast at I.2.10-11; Response to Staff Information Request D-36.C.2.

Cambridge states that such a survey "...is not cost justified due to the small overall contribution that Cambridge's residential class makes to system peak demand" (Response to Staff Information Request D-36.G). Cambridge supports its position with results from its load management simulation program (See section III B.3, infra). The results show that residential customers will comprise only 11.9 percent (24.2 MW out of 203.4 MW) of Cambridge's summer peak by 1993 (Response to Staff Information Request LM-3).

The Siting Council acknowledges that Cambridge's residential sales comprise a relatively small part of its total sales and that appliance saturation data are not required to forecast residential sales. Still, appliance saturation data might be useful to estimate the costs and benefits of such load management programs as controlled water-heaters and appliance efficiency rebates. The Siting Council encourages Cambridge to monitor in full the benefits and costs of an appliance saturation survey as it develops its load management plans (See section III.B.3, infra).

5. Belmont Municipal Light Department

In this filing, Cambridge has incorporated the forecast of sales to Belmont Municipal Light Department ("Belmont") as developed by the Massachusetts Municipal Wholesale Electric Company ("MMWEC") and analyzed by the Siting Council in its statutory reviews of MMWEC's forecast. This replaces Cambridge's previous practice of basing its forecast of sales to Belmont on growth rates provided by Belmont. The Siting Council is pleased with this change, which was recommended in the previous Decision, 9 DOMSC at 245 (1983).

6. Summary

Generally, the Siting Council commends Cambridge for continuing to improve its demand forecasting methodology. The Siting Council is pleased with the new methods for forecasting baseline commercial sales, residential heating sales, and residential non-heating sales, as well as the proposed revisions in the method for forecasting sales to existing industrial customers. The Siting Council is pleased with Cambridge's responsiveness to Siting Council suggestions and recommendations.

The Siting Council urges Cambridge to continue to upgrade its forecasting capabilities. Areas that deserve continued effort include: performance evaluations of forecasts provided by individual large commercial and industrial customers and by DPIS; alternative specifications for certain regression equations; and utilization of new data for both demand forecasting and demand management as the data become available.

The Siting Council hereby APPROVES the forecast methodology of Cambridge without Conditions.

D. Analysis of the Commonwealth Demand Forecast

1. Overview of the Methodology

Commonwealth has changed its forecast methodology substantially in each of its two previous filings with the Siting Council.

In its Third Annual Supplement to the First Long-Range Forecast, filed in 1979, Commonwealth relied heavily on the survey-interview technique. The Siting Council rejected this forecast methodology in its 1981 Decision, stating that it "...is based on seriously deficient statistical projection methods... is inherently subjective and burdensome to review, and inappropriate to the nature and size of the Companies' service area and the rigor required to develop a long-range electric demand forecast" In Re COM/Electric, 6 DOMSC 1, 7 (1981).

In its Second Long-Range Forecast, filed in 1982, Commonwealth replaced its survey-based forecast with a complex disaggregated end-use forecasting model adapted to its service territory from the NEPOOL model.[4] The new model consisted of an economic/demographic module (which produced forecasts of population, number of households, and employment by sector) and a power module (which produced forecasts of electricity demand for specific end-uses within the residential, commercial, industrial and miscellaneous sectors based on the outputs of the economic/demographic model).

The Siting Council accepted this forecasting model in its 1983 Decision, finding that it was "...appropriate, in line with the methodologies of similarly sized companies, and that it should ultimately provide the Companies with the support their supply planning effort needs," In Re COM/Electric, 9 DOMSC at 255 (1983). However, the Siting Council was concerned with the lack of service-territory specific data for the model, with the applicability of the model's demographic and employment modules, and with the predictive power of a model that had been calibrated to fit historical experience, 9 DOMSC at 262-263. Thus, the Siting Council attached four Conditions to its approval (See section II.A., *supra*).

In its current Forecast, Commonwealth continues to forecast demand with a disaggregated end-use model that consists of an economic/demographic module and a power module. However, Commonwealth has reduced its reliance on the NEPOOL model for data and model structure. In particular, Commonwealth has commissioned Data Resources, Incorporated ("DRI"), to provide demographic and economic forecasts for its service territory; has completely revised its methodology for

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4 The "NEPOOL model" was developed in 1976-77 by NEPOOL (the New England Power Pool, which is a consortium of almost all of New England's electric utilities) and Batelle Columbus Laboratories to produce long-term peak load and energy forecasts for New England. See "The NEPOOL Load Forecasting Model; An End-use Simulation Model for Long-Range Forecasting of New England's Electric Energy and Peak Demand," Load Forecasting Task Force of the NEPOOL Planning Committee, October 1981.

forecasting industrial demand, in conjunction with DRI; has obtained new data on average use per residential appliance and average use per commercial employee by sector; and has performed studies to obtain service-territory-specific data on price elasticities and the saturation of electric heat and air-conditioning into commercial floor space.

The Siting Council is pleased that Commonwealth is continuing to make major investments in upgrading and refining its demand model. In the sections that follow, the Siting Council reviews the demographic, economic, residential, commercial and industrial sectors of the model, along with the new estimates of price elasticities and Commonwealth's preliminary attempts to perform a sensitivity analysis of the model. The review focuses on changes in the methodology since the previous review and on Commonwealth's responses to Conditions imposed in the previous Siting Council Decision.

2. <u>The Demographic Forecast</u>

Commonwealth's forecast of the number of households in its service territory, provided by DRI, is almost completely new. Though Commonwealth continues to forecast population by adjusting population in the previous year for births, deaths and migration, it has changed its methodology for forecasting each of these adjustments.

Previously, Commonwealth had forecasted birth rates by trending the actual service-territory rate for 1979 to approach state-wide rates by the year 2000, and had forecasted death rates by trending the actual rate for 1979 with national trends, 9 DOMSC at 292-3 (1983). In this forecast, DRI projects birth and death rates on the basis of econometric relationships between historic rates in the service area and in the nation (Forecast at I.4.35, and Appendix A at 12-13).

Previously, Commonwealth had forecasted net migration rates as an econometric function of the difference between national and service-territory unemployment rates, using parameters estimated by NEPOOL, and adjusted for net commuting, migration rates for the elderly population, and immigration, 9 DOMSC at 293-6 (1983). In this forecast, DRI uses pooled time-series and cross-sectional data from Bristol, Plymouth, Barnstable and Dukes counties to estimate the historical relationship between migration and the differences between total service-territory employment and both state-wide and national employment (Forecast at I.4.35).[5]

Finally, Commonwealth had previously forecasted the number of households by applying age- and sex-specific household formation rates from 1970 Census data to individual population cohorts, 9 DOMSC at 296 (1983). In this forecast, Commonwealth uses newly available service-territory data from the 1980 Census to forecast household formation rates, with modifications through time to capture national trends (Forecast at I.4.35; Response to Staff Information Request D-24).

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5 The migration equation also includes a lag term. Forecast Appendix A at 24.

The Siting Council is pleased with each of these refinements. The Siting Council believes that forecasts based on statistically sound and theoretically plausible historical relationships, and using service-territory data, are more reliable than forecasts trended from one service-territory specific data point or based on data outside the service territory that is adjusted judgementally.

In particular, the migration equation implicitly accounts for persistent effects unrelated to employment differentials without discrete judgemental adjustments. Household formation rates are no longer sex-specific, but incorporate recent data and use reasonable trends for forecasting. Moreover, the results of DRI's population forecast were benchmarked to recent population data available through the Bureau of the Census, and to Commonwealth's 1982 demographic forecast (Response to Staff Information Request D-24).

The Siting Council recognizes that demographic forecasting is a difficult task. Nevertheless, Commonwealth (and DRI) have demonstrated that their demographic forecast is the output of a reasonable process that utilizes recent data and reasonable statistical methods. The Siting Council approves the current methodology and encourages Commonwealth to maintain this high level of effort in future forecasts.

3. The Employment Forecasts

Commonwealth's forecast of employment by sector, like its demographic forecast, was provided by DRI and is almost completely new.

To forecast manufacturing employment by two-digit Standard Industrial Classification ("SIC") code division, DRI weights historical employment in Commonwealth's service territory for each SIC code by the ratio of service-territory employment to state-wide employment for that SIC code in 1981, then constructs an employment index equal to the sum of the weighted employment values. DRI estimates an econometric relationship between total service-territory employment and this employment index using data from the Massachusetts Division of Employment Security ("DES"). DRI then uses this relationship in conjunction with outputs from DRI's Massachusetts employment model to forecast total service-territory employment over the forecast period. Finally, DRI allocates its forecast of total service-territory employment among individual SIC codes (Forecast section I.4, Appendix A at 8-10, 24-5 and 33).

Previously, Commonwealth had forecasted manufacturing employment by two-digit SIC code with a variety of different methods for different SIC codes, including relationships of service-territory employment to state-wide employment within the SIC code, time trends, and company judgement, 9 DOMSC at 299-303 (1983).

The Siting Council is pleased with Commonwealth's improvements. The Siting Council believes that the new methodology is a statistically sound one that avoids the hazards of relying wholly on subjective input to forecast manufacturing employment by SIC code.

DRI's forecast of non-manufacturing employment by sector relies heavily on DRI's forecasts of service-territory, statewide and national employment and personal income. In four non-manufacturing sectors,[6] DRI specifies that service-territory employment depends on both the level of internal economic activity (represented by the service area's share of the state's personal income and the state's share of national employment in the sector) and the influence of tourism (represented by national personal income). DRI specifies employment in the government sector as a function of statewide personal income; construction employment as a function of the level and rate of change of the service-territory's share of non-agricultural employment; and employment in the mining sector as constant (Forecast, section I.4, Appendix A at 10-12, 25-27 and 33-41; Response to Staff Information Request D-26).

Previously, Commonwealth had forecasted non-manufacturing employment by sector as a function of service-territory population, based on time trends, adoption of the Massachusetts trends predicted by NEPOOL, and judgemen, 9 DOMSC at 303-305 (1983).

Again, the Siting Council is pleased with Commonwealth's improvements. Considering that the four largest non-manufacturing sectors[7] account for over two-thirds of total employment in its service territory, it is appropriate that Commonwealth use detailed quantitative models to forecast employment in these sectors. The Siting Council encourages Commonwealth to continue to examine alternative specifications as required to improve model performance.

Finally, the Siting Council notes that Commonwealth's employment forecasts are now closely tied to DRI's national and regional economic models. The Siting Council encourages Commonwealth to monitor DRI's results for consistency with its own judgements, data, and knowledge of trends in its service territory.

4. <u>The Residential Forecast</u>

Commonwealth continues to forecast residential sales with an end-use model. The model forecasts total usage for each type of appliance as the product of average annual use-per-appliance and the total number of appliances in its service territory. Total residential sales is then the sum of total usage for each type of appliance.

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6 The four sectors are: services; wholesale and retail trade; finance, insurance and real estate; and transportation, communications and public utilities. Commonwealth specifically excludes employment at the large AT&T computer center and Otis Air Base from its employment data, though it is not clear how Commonwealth accounts for this in its use of personal income. See Section III.D.8, *infra*.

7 The four largest sectors are wholesale and retail trade; services; government; and finance, insurance and rate estate. Forecast at I.4.32.

Commonwealth identifies twelve major appliance types[8] used in its residential model (Forecast at I.4.44-55).

a. <u>The number of appliances</u>

To forecast the total number of appliances in its service territory, Commonwealth multiplies its forecasted number of households (disaggregated by age and type of house) by the saturation of appliances into each type of household in each age group. Commonwealth collects data on appliance saturation from periodic appliance saturation surveys and analysis, and accounts for time trends in appliance ownership through the use of survey results[9] and trend data from the NEPOOL model data base.

The Siting Council generally approved this method of forecasting the number of appliances in its previous Decision. The Siting Council encourages Commonwealth to continue to collect appliance saturation data and to upgrade its methodologies for forecasting saturation trends for individual appliances.

Though Commonwealth conducted appliance saturation surveys in 1979, 1980, and 1981, it does not state in its forecast whether it intends to repeat these surveys in the future (Forecast at I.4.29 and I.4.44-50). The Siting Council repeats here its statement in its previous Decision that saturation surveys, repeated periodically, will prove to be the best support for a reliable forecast of appliance saturations, 9 DOMSC at 308 (1983). These surveys are critical for verifying the applicability of saturation trends taken from NEPOOL or extrapolated from existing survey data. Verification is made more critical by the important contribution of Commonwealth's residential base load to the growth in the summer peak of the COM/Electric System (see Table S-3, <u>infra</u>).

Indeed, Commonwealth acknowledges the need for additional surveys by stating that "... 3 years of survey data is not sufficient to conduct a trend analysis" (Response to Staff Information Request D-27.E).

Thus, the Siting Council expects Commonwealth to document in its next forecast its intentions for repeating its appliance saturation surveys.

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8 The twelve major appliance types are: electric range, microwave oven, refrigerator, freezer, dishwasher, clothes washer, dryer, water heater, television, air conditioner, space heating and lighting. Forecast at I.4.44. Commonwealth also forecasts usage for fossil heating auxiliaries and second homes. Forecast, at I.4.50 and I.4.55.

9 Commonwealth hired Consulting Statisticians, Inc., to conduct a multidimensioned contingency table analysis of the data in its appliance saturation surveys. This analysis was used to improve Commonwealth's forecasts of individual saturation rates. Forecast at I.4.29.

Commonwealth forecasts separately the penetration rate of electric space heating. First, Commonwealth defines a cost variable that represents the net difference in annual amortized ownership and operating cost between electric and oil heating systems. Next, Commonwealth estimates an econometric relationship between historical penetration rates in its service territory and the cost variable. Last, Commonwealth uses this econometric relationship, in conjunction with a forecast of the cost variable, to forecast the penetration rate (Forecast at I.4.48; Responses to Staff Information Requests D-14, D-15 and D-27).

The Siting Council notes that the regression performed well. Moreover, the Siting Council is pleased that Commonwealth has experimented with alternative specifications of the econometric relationship (Id.). The Siting Council is satisfied that the current forecast of penetration rates is the output of an acceptable process, and therefore is itself acceptable.

Still, the Siting Council must acknowledge the potential for structural changes in the new home heating market which might affect the penetration rate of electric heating in the future. The Siting Council has seen evidence in another proceeding of the increased availability of natural gas on Cape Cod (See In Re Colonial Gas, 11 DOMSC 111 at 121, 131). Moreover, Commonwealth's econometric relationship is based on only seven years of data, which does not instill confidence in its long-term applicability.

Therefore, the Siting Council requests Commonwealth to monitor developments in the residential space heating market, and to report significant impacts on the penetration rate of electric space heating in its next forecast.

b. Average use per appliance

Commonwealth's previous methodology for forecasting average use-per-appliance (forecasted as the product of total connected load and the fraction of connected load operating) was the subject of Condition 2 to the Siting Council's previous Decision.

Specifically, the Siting Council ordered Commonwealth to review the availability of data on residential appliance connected loads and use profiles, to demonstrate the applicability of data from the NEPOOL model to Commonwealth's service territory, and to address appropriate changes in the residential data base. In its Decision, the Siting Council criticized Commonwealth's usage of data that were outdated, collected outside of New England, and based on sets of households with demographic characteristics that vary markedly from those in Commonwealth's service territory, 9 DOMSC at 264, 309-317 (1983).

Commonwealth responded to Condition 2 by changing both its method of calculating average use per appliance and its sources of data. Specifically, Commonwealth no longer uses data on total connected load to calculate average use-per-appliance. Instead, Commonwealth uses data that it has collected on annual average use-per-appliance, modified to reflect responses to price increases and changes in appliance efficiency that have occurred since 1970 (Forecast at I.4.12-14).

Table 2 shows the data on annual average appliance usage that Commonwealth uses in its forecast. In addition, the table lists the sources of those data and the number of alternative data sources that Commonwealth states it examined for each appliance, as well as the range of appliance usage estimates taken from those sources. Note the wide range of appliance usage estimates in the published literature.

The Siting Council commends Commonwealth for its efforts in examining a significant sample of data sources, and for its efforts to replace old data from a variety of geographic sources with more recent data from the northeast region. This represents a credible attempt by the Company to optimize its use of available data.

Moreover, the Siting Council is pleased with Commonwealth's decision to use average annual usage data instead of connected load data. This decision results in a better match between model structure and data availability. It avoids the need for "level adjustments" and calibration of the NEPOOL model data, which the Siting Council has criticized in previous Decisions (See In Re MMWEC, 11 DOMSC 237, 257-59 (1984); In Re EUA, 11 DOMSC 61, 76-79 (1984)).

Therefore, the Siting Council is satisfied that Commonwealth has complied with the thrust of Condition 2 to its previous Decision.

Nevertheless, the Siting Council remains concerned with the reliability of the available appliance usage data. For several end-uses (e.g., lighting), Commonwealth continues to rely on old data that are adjusted for application in the forecast. The Siting Council's concerns are heightened by the uncertain future of federally mandated appliance efficiency standards (Forecast at I.4.51), conflicting evidence on the response of appliance usage to price decreases (see section II.D.7, infra), the lack of evidence regarding relationships between appliance usage rates and income, and the potential for the introduction of new appliances and end-uses. In light of the significant contribution of residential appliances to the peak load of the COM/Electric System (see Table S-3, infra), the Siting Council encourages Commonwealth to monitor these and other effects on its estimates of appliance usage as appropriate.

Finally, the Siting Council encourages the evaluation of alternate strategies for obtaining appliance usage data, including sub-metering studies, conditional demand studies, and end-use allocation studies. In future forecasts, the Siting Council expects Commonwealth to supply the sources of its appliance usage data; to state the year in which the data measurements were originally taken, along with the year to which the data are adjusted for application in the forecast; to identify

TABLE 2
Sources of Annual Appliance Usage Data

Appliance	Average Use (KWH/year)	Source[a]	Number of Sources	Range of Values (KWH/year)
Space heating	7588	Comm.	15	2558 - 14153
Off-peak water heating	3710	MRI-US	20	2628 - 5400
Water heating	3440			
Refrigerator (frost-free)	1874	MRI-NE	20	297 - 2250
Central A/C	1800	EEI/NEPOOL	11	798 - 3800
Freezer (frost-free)	1626	MRI-NE	11	1280 - 1985
Refrigerator (standard)	1249	MRI-NE	19	232 - 1500
Clothes dryer	1124	MRI-NE	25	714 - 1363
Freezer (standard)	1063	MRI-NE	13	323 - 1560
Range	821	MRI-NE	20	492 - 2587
Lighting	534	NEPOOL	N.A.[b]	
Room A/C	516	EEI	14	140 - 2000
TV - color	320	EEI	16	320 - 1205
Misc. use	312	Comm.	N.A.[b]	
Microwave oven	190	EEI	9	80 - 300
Fossil heat auxiliaries	153	NEPOOL	N.A.[b]	
Dishwasher	149	MRI-US	18	149 - 886
TV - B/W	100	EEI	16	100 - 652
Clothes washer	77	MRI-NE	15	65 - 108

Sources: Forecast at I.4.12-14; Response to Information Request D-28.C.

Notes: [a] Sources are referenced as follows:

Comm. Derived from Commonwealth's sales or load research data.

MRI EPRI paper EA-682, Patterns of Energy Use by Electrical Appliances, prepared by the Midwest Research Institute using data collected in 1977. "US" signifies data for the nation as a whole. "NE" signifies data for the northeast region.

EEI Edison Electric Institute, EEI Pub. #75-61 Rev., used to obtain data for the model in 1982. "EEI/NEPOOL" data used average wattage ratings from NEPOOL model data.

[b] Commonwealth calculates miscellaneous use as a residual for the model initialization year, then allows it to respond to price changes. Lighting usage is taken from the NEPOOL model (from a report dated 1961-62) and adjusted for Commonwealth's house size and household size for 1980. Fossil heat auxiliary use is NEPOOL data for New England. Forecast, at I.4.14; Response to Staff Information Request D-28.C.

alternative sources of data that were considered by Commonwealth; and to state why Commonwealth believes that the data it used in the forecast are superior to the alternatives.

5. The Commercial Forecast

Commonwealth continues to forecast commercial sales with an end-use model. The model forecasts annual energy consumption for three end-uses and seven commercial sectors[10] as the product of the number of employees in the sector and the average annual use-per-employee for each end-use. Total commercial demand is then the sum of total annual energy consumption for all end-uses and sectors (Forecast at I.4.56-59). See section II.D.3, supra, for an analysis of the forecast of commercial employment by sector.

Commonwealth's previous methodology for forecasting average annual use-per employee (based on NEPOOL's data and model structure) was the subject of Condition 3 to the Siting Council's previous Decision.

Specifically, the Siting Council ordered Commonwealth to review the availability of data on commercial use-per-employee, to demonstrate the applicability of NEPOOL's data and methods to Commonwealth's service territory, and to address appropriate changes in the commercial data base. In its Decision, the Siting Council criticized: Commonwealth's use of NEPOOL data on base load usage in the retail sector to estimate base load usage in the other commercial categories; Commonwealth's "level adjustments" to improve the fit between the model's results and actual historical data; and Commonwealth's treatment of end-use saturations in the commercial models, 9 DOMSC at 318-325 (1983).

Commonwealth responded to Condition 3 by changing both its sources of data and its methods of calculating use-per-employee for each of the three commercial end-uses.

To calculate use-per-employee for the temperature-sensitive end-uses (heating and cooling), Commonwealth uses actual data on monthly sales by rate class and the number of degree-days ("DDs") per month to develop econometric relationships for temperature-sensitive use per customer per DD. Commonwealth develops relationships for three sets of rate classes and end-uses ---- winter heating use by commercial heating

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10 The three end-uses are: heating use, including electric space heating and fossil heating auxiliaries; cooling use; and base load use, including lighting and miscellaneous use. The seven commercial sectors are: services; wholesale trade; retail trade; transportation, communications and public utilities; state and local government, including military; finance, insurance and real estate; and construction, agriculture, forestry, fishing and mining. (Forecast at I.4.59).

customers, winter heating use by commercial non-heating customers, and summer cooling use by commercial customers.[11]

Next, Commonwealth calculates total commercial (excluding municipal) temperature-sensitive load from these estimates of use per customer per DD, actual data on the number of customers by rate class, and actual DD data.

Then, Commonwealth allocates this estimate of total commercial temperature-sensitive load to the six non-governmental commercial sectors. At the same time, Commonwealth splits heating loads into two parts for each sector: electric space heating and fossil heating auxiliaries. The allocations use service-territory specific saturations, prices and employment data, as well as data derived from a run of the Commonwealth Model that uses NEPOOL's data on use per customer per DD.

Finally, for each sector and end-use, Commonwealth divides the temperature-sensitive load by the normal number of DD and the actual number of employees in heated or cooled space, thereby producing the estimates of use per employee per DD by end-use by sector. Commonwealth assumes that these values react to price changes over the forecast period via the model's price elasticity logic (see section II.D.7, infra) (Forecast at I.4.15-18, and I.4.56-60; Responses to Staff Information Requests D-18, D-19, D-20, D-21 and D-29).

The Siting Council is generally pleased with Commonwealth's new methodology, and considers it a significant improvement over the previous practice of relying on NEPOOL's regressions and data. Further, the new method apparently avoids the need for "level adjustments" of data derived from NEPOOL's data base ---- a practice that the Siting Council criticized strongly in the previous Decision, 9 DOMSC at 259-260 (1983).

Still, the Siting Council is concerned with one link in the new logic ---- the allocation of temperature-sensitive commercial load among the six commercial sectors. This allocation procedure is one place where Commonwealth could improve its documentation. It is not clear from the Forecast how Commonwealth uses NEPOOL's incremental temperature-sensitive load coefficients. In light of its continuing concern with the applicability of these data to Commonwealth's service territory, the Siting Council hereby requests Commonwealth to document in detail in its next forecast the procedure it uses to allocate temperature-sensitive commercial load among its commercial sectors.

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11 Commonwealth also develops an econometric relationship for heating use by municipal non-heating customers to estimate temperature-sensitive use per customer in the government sector. Commonwealth calculates temperature-sensitive use in the government sector separately from its calculations in the other commercial sectors. Forecast at I.4.16.

To calculate base-load use per employee by sector, Commonwealth subtracts its estimate of temperature-sensitive sales from total sales for each sector, then divides by the number of employees in that sector. The results are shown in Table 3 for the five years for which sales data are available by sector. Commonwealth assumes that the base-load use per employee data remain constant over the forecast period (except for responses to price changes) at either the historic average or the 1982 level (Forecast at I.4.60-61; Responses to Staff Information Requests D-17 and D-29.F).

TABLE 3
Historic data on commercial sector KWH-per-employee, by sector.

Commercial sector	1978	1979	1980	1981	1982	Five-year Average	Standard Deviation
Trans.,Comm, Utilities	9585	9678	10294	11871	11891	10664	1144
Services	12095	11087	9418	9156	9473	10246	1284
Fin., Ins., Real Estate	8094	7823	8142	7623	7016	7740	456
Retail Trade	7127	7466	7104	7288	8190	7435	446
Wholesale Trade	4330	4758	4594	4687	5174	4709	307
Government	3909	4310	3479	3547	3527	3754	355
Cons., Agr., Fish. etc.	1383	1216	1229	1245	1461	1307	109

Source: Forecast at I.4.61.

The Siting Council has several concerns with Commonwealth's new methodology. First, Commonwealth does not account for long-term changes in base-load use per employee that may result from efficiency improvements, technical change, or factor substitution.[12] Also, Commonwealth does not present sufficient data for the Siting Council to have full confidence in their reliability for a long-term forecast.

On the other hand, the Siting Council notes that the data presented in Table 3 appear to be relatively stable.[13] This stability not only adds support for the appropriateness of Commonwealth's methodology, but also instills confidence in the derivation of the data on temperature-sensitive use per employee, from which the base load data are derived. Certainly, the new methodology is an improvement over Commonwealth's previous reliance on NEPOOL data and the base load retail trade survey that the Siting Council criticized strongly in its previous Decision, 9 DOMSC at 318-320 (1983).

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12 Factor substitition might include, for example, substitution of capital for labor (or vice versa) in response to exogenous factors.

13 Commonwealth reviewed and redefined some of its SIC code designations in 1980, which explains some of the variation in the data for that year. Response to Staff Information Request D-29 E.

Because of these improvements, and because of Commonwealth's obvious efforts to improve this part of its demand forecast, the Siting Council hereby finds that Commonwealth has complied with Condition 3.

Nevertheless, the Siting Council remains concerned with the reliability of the data available for forecasting commercial demand in the long term. The Siting Council encourages Commonwealth to continue to collect appropriate data on commercial demand, including data on temperature-sensitive use by sector; to investigate methods for determining base load use and temperature-sensitive use by sector from its existing data on total use by sector; to consider the feasibility of monitoring a sample of customers within each commercial sector for determination of base and temperature-sensitive loads; and to report its progress in these and other areas in its next forecast.

Finally, the Siting Council acknowledges here that Commonwealth has performed a survey to determine the saturation rates of electric space heat and air conditioning into its service territory. The Siting Council is pleased both with Commonwealth's commitment to invest resources in obtaining service-territory-specific data for its forecast of commercial demand, and with its stated intent to repeat the survey at three-year intervals in order to monitor saturation trends (Forecast at I.4.81-84; Response to Staff Information Request D-29.A).

6. The Industrial Forecast

In this filing, Commonwealth uses a completely new methodology to forecast industrial sales. Commonwealth no longer uses the method adapted from NEPOOL of forecasting value-added and KWH-per-dollar value-added for individual two-digit SIC codes. Instead, Commonwealth forecasts total industrial sales as an econometric function of real electricity price and an industrial production index, then uses historical data to allocate total industrial sales to individual SIC codes. The industrial production index is the sum of the national production index for each two-digit SIC code as forecasted by DRI, weighted by the share of total service-territory employment for that SIC code (See section II.D.3, supra) (Forecast at I.4.62-63 and Appendix A at 2-7).

The Siting Council approves of this change. In its previous Decision, the Siting Council criticized the use of value-added data to forecast industrial demand, citing the lack of data applicable to Commonwealth's service territory, the small sample sizes of available data, and the reliance on numerous assumptions that may or may not be reasonable, 9 DOMSC at 325-7 (1983). The new methodology requires less data and fewer unverified assumptions than the value-added method. The Siting Council believes the new methodology to be a more reliable and cost-effective way to forecast industrial sales.

Nevertheless, the Siting Council notes that the present methodology relies heavily on DRI's forecast of national production indexes for individual industries. Though the theory behind the new methodology appears sound, and the regression results seem reasonable, the Siting Council would prefer Commonwealth to forecast industrial sales using service-territory-specific data by SIC code.[14] Indeed, Commonwealth states its intent to do so as sufficient data become available ---- Commonwealth has only collected industrial sales data by SIC code since 1978 (Response to Staff Information Request D.30.D). In the interim, the Siting Council accepts the current industrial forecasting methodology.

7. Price Elasticities

Commonwealth incorporates price elasticities explicitly in its forecasts of residential and commercial demand.

Specifically, Commonwealth begins by forecasting electricity prices for each of its rate classes.[15] Then, Commonwealth assumes that customers reduce their usage rates (i.e., residential average use per appliance, commercial use per employee) in response to price increases. The price elasticities define the magnitude of the reduction in usage for a given price increase. Commonwealth assumes that the full response to a given price increase occurs over a ten-year period, and that residential customers do not respond to short-run price decreases (Forecast at I.4.65-67).

The Siting Council is pleased that Commonwealth accounts for price effects so explicitly. Still, the Siting Council notes that the reliability of the price-response algorithm depends on both the quality of available data and the structure of the price-response model.

In its previous forecast, Commonwealth based its price elasticities on a NEPOOL review of numerous price-elasticity studies. In its Decision, the Siting Council was critical of the NEPOOL elasticities, citing the wide ranges of values found in the NEPOOL literature review, the differences between NEPOOL's average values and the values produced by Commonwealth's model, and the inapplicability of data from various times and geographic locations to Commonwealth's service territory during the forecast period, 9 DOMSC at 328-330 (1983). Thus, as Condition 4 to that Decision, the Siting Council ordered Commonwealth to perform an aggregate price elasticity study for its service area (See section II.A., *supra*).

Commonwealth responded to Condition 4 by performing aggregate price elasticity studies for three residential sub-classes (heating, non-heating, and water-heating) and the combined commercial/municipal

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14 See *In Re Boston Edison*, 10 DOMSC 203, 232-237 (1984) for a recent Siting Council review of a forecast of industrial sales that uses SIC code data from one utility's service territory.

15 Commonwealth forecasts prices for the following classes: residential total, residential heating, off-peak water heating, commercial, industrial, and street lighting. Electricity prices are forecasted as the sum of the power cost charge -- based on the output of Commonwealth's production cost simulator as adjusted for purchased power and transmission costs -- and base costs by customer class -- based on the difference between estimated revenue requirements and the then-effective power cost charge, as escalated by a forecast of the GNP deflator. Forecast at I.4.77-78.

class. Commonwealth used regression analysis to develop short- and long-term elasticities from 12 years of annual data for each class. Commonwealth then compared the class-wide elasticities based on its study with class-wide elasticities derived from NEPOOL's end-use elasticities and weighted by Commonwealth sales data (Forecast at I.4.19-24; Response to Staff Information Request D-11).

Table 4 shows the results of Commonwealth's price elasticity study.

Part A of the table shows short- and long-run elasticities for four of Commonwealth's rate classes. These elasticities were derived from the coefficients of regression equations that used actual data on electricity consumption by class, electricity price, and electricity consumption lagged one year.[16,17] Though some of the t-statistics on the regression coefficients are low, the Siting Council believes that the regression results appear to be reasonable, because of the strong theoretical basis for the specifications and the relatively high amount of variation in the dependent variable that is explained (Forecast at I.4.22-25).

Part B compares the class-wide elasticities derived from Commonwealth's study to the class-wide elasticities based on NEPOOL's end-use elasticities. For the residential class, the two class-wide long-run elasticities are quite similar. Thus, Commonwealth decided to continue to use most of the NEPOOL-based elasticities in its forecast of residential demand. In contrast, for the commercial/municipal class, the two long-run elasticities are quite different. Here, Commonwealth decided to use end-use elasticities derived from its study in place of the NEPOOL-based elasticities. Commonwealth calculated elasticities for six end uses from the class-wide elasticity through an allocation procedure that used the NEPOOL end-use elasticities, and Commonwealth data on consumption by end use (Forecast at I.4.20).[18]

Part C compares the commercial end-use elasticities derived from NEPOOL data with those used in the forecast. Part D compares NEPOOL-based elasticities for two residential end uses with those

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16 The residential heating equation used average annual use per heating degree day as a proxy for electricity consumption. Forecast at I.4.22.

17 These regressions used the so-called "Koyck-lag specification." See Response to Staff Information Request D-11, and Pindyck, Robert S. and Daniel L. Rubenfeld, Econometric Models and Economic Forecasting, Second Edition, at 232-233.

18 Note that Commonwealth based its decisions on the applicability of NEPOOL elasticities on the relative values of the long-run elasticities, not the short-run elasticities. Commonwealth believes that long-run elasticities have more of an impact on the results of a long-term forecast than short-run elasticities. Commonwealth also considered the impacts of the different number of residential and commercial end-uses. See letter from George Aronson, Siting Council Staff, to Robert Fratto, Commonwealth, dated April 12, 1985.

TABLE 4
Results of the Aggregate Class Elasticity Study

A. Elasticities derived from regressions using Commonwealth's data.

Class	Short-run Elasticity	Long-Run Elasticity
Residential Heating	-0.520	-0.827
Residental Non-Heating	-0.144	-0.670
Residential Water Heating	-0.081	-0.096
Commercial/Municipal	-0.206	-1.355

B. Comparison of NEPOOL-based and Commonwealth class-wide elasticities.

	Short-run Elasticity		Long-run Elasticity	
	Commonwealth	NEPOOL	Commonwealth	NEPOOL
Residential	-0.220	-0.338	-0.682	-0.601
Commercial/Municipal	-0.206	-0.29	-1.355	-0.83

C. Comparison of NEPOOL-based and Commonwealth commercial end-use elasticities.

Lighting	-0.20	-0.25	-1.40	-0.80
Miscellaneous Base Load	-0.18	-0.25	-1.30	-0.80
Air Conditioning	-0.36	-0.50	-2.00	-1.20
Electric Space Heating	-0.36	-0.50	-1.50	-0.90
Fossil Heating Auxiliaries	-0.40	-0.50	-0.80	-0.90
Street Lighting	-0.30	-0.3	-1.00	-1.00

D. Comparison of NEPOOL-based and adjusted Commonwealth residential end-use elasticities.

Electric Space Heating	-0.88	-0.7	-1.00	-1.5
Fossil Heating Auxiliaries	-0.40	-0.7	-0.8	-1.5

Sources: Forecast at I.4.20-25 and I.4.66; Response to Staff Information Request D-33; Letter from George Aronson, Siting Council Staff, to Robert Fratto, Commonwealth, dated April 12, 1985.

derived from the Commonwealth study and used in the forecast. Note that the Commonwealth and NEPOOL-based end use elasticities are quite comparable for some end uses, but quite different for other end uses.

Generally, the Siting Council is satisfied that Commonwealth has performed the required aggregate price elasticity study in an acceptable fashion. Commonwealth has estimated service-territory-specific end use elasticities for its commercial model, and has adequately justified the applicability of NEPOOL-based class-wide elasticities in the residental class.

Still, the Siting Council is somewhat concerned with the variations in end-use elasticities. The Siting Council notes that it is possible that end-use elasticities taken from NEPOOL may be inapplicable to individual residential end-uses in Commonwealth's service-territory, despite the apparent applicability of the class-wide elasticities. The Siting Council would appreciate comments by Commonwealth regarding the impacts of this effect in its next filing.

Nevertheless, in light of the difficulties inherent in any estimate of end-use elasticities, and the likelihood that the impacts of variations in individual end-use elasticies are negligible (and in recognition of Commonwealth's laudable efforts to improve the reliability of this part of its forecast), the Siting Council finds that Commonwealth has complied with those sections of Condition 4 requiring it to demonstrate the applicability of NEPOOL elasticities and to study price elasticities.

In addition to price elasticities, Condition 4 also required Commonwealth to study income and cross-price elasticities. Commonwealth did so by testing the significance of income and fuel prices as explanatory variables in the regression equations which form the basis for its estimates of class-wide elasticities. The regressions performed poorly; thus, Commonwealth concluded that the income and cross-price elasticities were insignificant. Commonwealth supported its conclusion by citing a survey by the Electric Power Research Institute of 29 residential electricity demand studies, which found that income elasticities are frequently insignificant and generally unstable. Moreover, Commonwealth states that responsiveness to oil prices is accounted for elsewhere in the Forecast in the residential penetration equation (Forecast at I.4.19-20; Responses to Staff Information Requests D-33.D and D-33.E).

The Siting Council finds that Commonwealth has made a good faith effort to study income and cross-price elasticities.[19] Therefore, the Siting Council finds that Commonwealth has complied with Condition 4.

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19 The Siting Council does have one concern with the theoretical basis for inclusion of additional explanatory variables in a Koyck-lag specification. Specifically, the Koyck-lag specification is derived as the difference between two equations using the values of variables at different times. Pindyck and Rubenfeld, <u>supra</u> n. 17 at (Footnote continued on next page)

Finally, the Siting Council questions Commonwealth's assumption that residential customers do not react positively in the short term to declining prices, since this assumption seems to conflict with prevailing theory (Forecast at I.4.65). If Commonwealth chooses to continue this practice in future forecasts, the Siting Council requests Commonwealth to document its reasons for doing so in detail.

8. Miscellaneous Forecasts

Commonwealth forecasts energy consumption for categories not included in any other sector. These categories include: street lighting, internal consumption in the Canal Power Plant, unbilled sales, company use, system losses, and sales to Otis Air Force Base ("Otis") and a new AT & T computer center (Forecast at I.4.64). Commonwealth also integrates its energy forecasts with an hourly load model to produce its forecasts of peak demand and hourly load profiles (Forecast, at I.4.70-76).

Otis and AT&T are large individual customers of Commonwealth. Commonwealth projects that AT&T's demand will rise from 46,500 MWH in 1984 to 75,000 MWH per year after 1985, and that Otis's demand will stay at 12,500 MWH per year through the forecast period. Sales and employment at AT&T and Otis are not included in Commonwealth's calculations of KWH, employment, or KWH per employee for its forecast of commercial demand (Forecast at I.4.64; Response to Staff Information Request D-31).

The Siting Council appreciates the value of explicit treatment of unusually large customers, and commends Commonwealth's efforts to avoid double-counting.

Regarding the forecast of peak demand, Commonwealth describes major improvements in the quality of the data used in its hourly load model. In particular, Commonwealth is replacing NEPOOL data with data from its own research into consumption patterns in the commercial and industrial sectors. Commonwealth is also refining its usage of temperature data for forecasting temperature-sensitive loads (Forecast at I.4.73).

The Siting Council is pleased with those improvements, as they evidence Commonwealth's commitment to invest resources in the production of quality data for its models. The Siting Council encourages Commonwealth to continue to upgrade the quality of its data (see section III.B.3, infra).

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19 Continued

233, Equation 9.4. Inclusion of additional explanatory variables would require use of weighted averages of two values of these variables. The significance of this effect is not clear, but the Siting Council Staff would be willing to discuss it with Commonwealth upon request.

9. Sensitivity Analysis

In its previous Decision, the Siting Council expressed its concern with the overall sensitivity of the Commonwealth model to changes in its data inputs or parameters, given the uncertain quality of some of the input data. As Condition 1 to that Decision, the Siting Council ordered Commonwealth to conduct a sensitivity analysis of its demand model, 9 DOMSC at 263 (1983); see section II.A., supra.

In response, Commonwealth analyzes the sensitivity of model results to selected input variables. Commonwealth does not present a complete sensitivity analysis, stating that such an analysis (Forecast at I.4.11):

> ...would encompass more than 250 model runs, with many runs involving major data base changes. Without additional software to facilitate this task, the commitment that would be required... is not justified.

Instead, Commonwealth selects for its analysis the model inputs that are based on data from outside its service territory. Commonwealth determines the percentage change in total net energy demand and class-wide demand that results by 1993 from a five percent change in each input.

Table 5 lists the variables that Commonwealth examines in its sensitivity analysis, along with selected results of the analysis (Forecast at I.4.11 and I.4.85-100).

The Siting Council notes the wide range of responses to the same amount of variation in different variables. The forecast of net energy appears to be most sensitive to variations in commercial base load use per employee (See section II.D.5, supra), average annual use per residential appliance (See section II.D.4, supra), and oil heating system thermal efficiency (which affects the penetration rate for electric space heating ---- see section II.D.3, supra). In contrast, the forecast appears to be comparatively insensitive to variations in values of elasticities for most individual end uses.

Generally, the Siting Council is pleased with Commonwealth's sensitivity analysis, insofar as it quantifies the overall sensitivity of the demand forecast to certain changes in individual parameters and data inputs. This allows Commonwealth to improve its evaluation of the benefits to the forecast of specific investments in data collection. In addition, it allows the Siting Council to review the trade-offs between the reliability of data that are not service-territory specific and the appropriateness of their use in the forecast.

The Siting Council notes that the sensitivity analysis raises broader issues surrounding the nature of the variables tested, the magnitude of the variation of each input variable, and the interpretation and use of the results.

TABLE 5
Results of Commonwealth's Sensitivity Analysis

A. Variables included in the sensitivity analysis.

Variable name	Description
HFT	Household formation trends
SHTR	Second home trends
COST3	Oil heating system thermal efficiency
TSATR	Appliance saturation trends (for eight appliances)
RELL	Long-run residential price elasticity (17 values)
RELS	Short-run residential price elasticity (17 values)
AUSE70	Appliance average use in 1970 (for 15 appliances)
AWYR	Appliance efficiency trends (for 11 appliances)
HSAU	Housing size adjustments to average use
MWER	Range average use adjustment for microwave saturation
CBASE	Commercial base load use-per-employee (for seven commercial sectors)
C2	Commercial air-conditioning saturation trends (for seven commercial sectors)

B. Response to a five percent change in the input variable.

	Percent change by 1993 in:	
Variable name	Residential energy	Total net energy
AUSE70 - Frost free refrigerator	0.96	0.42
COST3	0.86	0.38
AUSE70 - Dryer	0.49	0.22
AUSE70 - Lighting	0.43	0.19
HFT	0.325	0.135
AUSE70 - Range	0.32	0.14
RELL - Space heating*	0.23	0.10
AUSE70 - Color TV	0.22	0.10
AUSE70 - Room A/C	0.20	0.09
AWYR - Frost free refrigerator	0.19	0.08
AUSE70 - Standard refrigerator	0.15	0.06
RELS - Dryer usage*	0.15	0.06
RELL - Dryer usage*	0.11	0.05
Other residential variables tested	less than 0.1	less than 0.05

	Percent change by 1993 in:	
Variable name	Commercial energy	Total net energy
CBASE - Retail trade	1.38	0.42
CBASE - Services	1.38	0.42
CBASE - Trans., comm. and util.	0.36	0.11
CBASE - Government	0.35	0.11
CBASE - Fin., ins. and real estate	0.32	0.10
CBASE - Wholesale trade	0.12	0.04
Other commercial variables tested	less than 0.1	less than 0.04

Source: Forecast, at I.4.85-100.
Note: * Responses to increases in these variables are different from responses to decreases. Values shown are the responses to decreases.

Commonwealth limits its sensitivity analysis to variables that are not based on service-territory-specific data (Forecast at I.4.11). However, the Siting Council feels that other types of variables should be analyzed for their impact on the demand forecast. Such variables might include: exogenous variables that are difficult to forecast; certain exogenous variables whose forecasts are supplied by DRI; forecasts of trends that are based on a small sample of surveys; and data for which different estimation methods yield significantly different results.

Commonwealth's practice of varying each input variable by the same percentage is useful for comparing the relative sensitivity of different variables. However, the range of values that should be tested is different for each variable. For example, the published data on annual use per residential appliance vary widely depending on the reference (see Table 2, supra); in contrast, the historical data on base load use per employee by commercial sector appear to vary little from year to year (See Table 3, supra).

Further, the sensitivity analysis should be designed to optimize the usefulness of the demand forecast as a planning tool. In addition to its use for evaluating data collection efforts, the sensitivity analysis should also help Commonwealth to understand the impacts of changes in exogenous variables on its strategies for supply planning and demand management.

Admittedly, these broader issues signify a shift in the Siting Council's conception of a sensitivity analysis ---- from that of a diagnostic tool for improvement of forecast reliability, to that of a planning tool that serves as part of the basis for supply-side decision-making. In view of this shift, the Siting Council is satisfied that Commonwealth has complied with the original intent of Condition 1 as imposed in the previous Decision.

However, the Siting Council would like Commonwealth to continue to develop its sensitivity analysis of its demand model. To this end, the Siting Council hereby requests Commonwealth in its next forecast to identify significant variables that should be analyzed for their impact on the demand forecast and to state why these variables were chosen; to identify an appropriate range of variation for each variable; to identify interrelationships that affect the selection of individual variables and ranges of values; to document the results of available sensitivity analyses performed on these variables; and to describe the uses of the results for supply side and demand management decision-making. Commonwealth is encouraged to meet with Siting Council staff to clarify the scope of this request.

10. Summary

Generally, the Siting Council is pleased with the major improvements in Commonwealth's demand forecasting methodology. In particular, the Siting Council commends Commonwealth for its thorough responses to Conditions imposed upon it in the previous Decision; for its new demographic and employment models, developed in conjunction with DRI; for its decisions to change its residential and industrial models to implement a better match between model structure and data availability; for its improvement of its data on commercial use, commercial saturations, end use elasticities, and residential appliance usage; and for its preliminary steps to conduct a sensitivity analysis of the demand forecast.

The Siting Council notes that Commonwealth's model appears to be well documented and generally appropriate to the size and nature of Commonwealth's service territory. Indeed, Commonwealth has developed its methodology to the point where it can shift its focus from major development efforts to model maintenance and refinement, and to increasing its use of the demand forecast as a planning tool. Areas where the Siting Council believes further maintenance and refinement are warranted include: the reliability of data on residential appliance usage and commercial end use load by sector; collection of data on industrial use by SIC code; repetition of the residential appliance saturation survey; and monitoring of the penetration rates of electric space heating. In addition, the Siting Council encourages Commonwealth to refine its use of the sensitivity analysis as a tool to evaluate improvements in forecast reliability.

The Siting Council hereby APPROVES the demand forecast methodology of Commonwealth without Conditions.

III. ANALYSIS OF THE SUPPLY PLAN

A. Standard of Review

In keeping with its mandate to "provide a necessary power supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost", Mass. Gen. Law. Ann., ch. 164, sec. 69J, the Siting Council reviews three dimensions of utility supply planning. 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. The diversity of supply measures the reliability of a utility's mix of supply sources and facility types. The Siting Council's working principle is that a more diverse supply mix, like a diversified financial portfolio, is more reliable. The Siting Council also addresses whether a supply plan minimizes the long-run cost of power subject to the trade-offs with adequacy, diversity, and the environmental impacts of new facility construction and operation. In Re Boston Edison, 7 DOMSC 93, 146 (1982); In Re NEES, 7 DOMSC 270, 306 (1982). Finally, the Siting Council reviews utility demand management programs, cogeneration projects and small power production efforts on the same basis as the consideration of new conventional bulk power facilities when analyzing the adequacy, diversity and cost of a supply plan. In Re Boston Edison, 10 DOMSC 203, 248 (1984); In Re EUA, 11 DOMSC 61, 96 (1984).

The Companies state in their forecast that "Cambridge, Canal and Commonwealth plan and operate their generating facilities as a single entity and act as one participant within the New England Power Pool" ("NEPOOL"). Consequently, the Siting Council reviews the adequacy, diversity and cost of the supply plan for these three companies as a single system. It follows that the findings of this review apply to the supply plan of the System as a whole, and are not necessarily applicable to the supply adequacy or need for facilities by any of the individual companies.

B. Adequacy of the Supply Plan

COM/Electric forecasts significant growth in its peak load and reserve requirements. However, the System does not forecast having adequate capacity to meet its requirements throughout the forecast period.

The System's load requirements are illustrated in Table S-1. The System (including Belmont) forecasts that its winter peak load will grow at a compound rate of 2.1 percent from 1985-1993; its summer peak load, at a compound rate of 2.3 percent. Over the same period, the System forecasts that its "capability responsibility" ---- the sum of forecasted peak loads and the reserve capacity required to meet NEPOOL reliability standards ---- will grow at a compound rate of 2.9 percent per year.

Table S-1

COM/ELECTRIC SYSTEM PEAK LOADS AND RESERVE REQUIREMENTS

	1985	1986	1987	1988	1989	1990	1991	1992	1993
A. Winter peak load[a]									
Commonwealth	518	534	548	563	577	591	602	613	626
Cambridge	156	158	160	163	166	167	168	169	170
Belmont	20	20	20	20	20	21	21	21	21
System peak load[b]	694	712	728	746	763	779	791	803	817
NEPOOL capability responsibility[c]	819	847	886	893	908	932	952	986	1020
B. Summer peak[a]									
Commonwealth	497	514	531	545	561	575	588	599	609
Cambridge	203	205	208	211	215	219	222	223	223
Belmont	20	20	20	20	20	20	20	20	21
System peak load[b]	706	726	746	764	783	801	818	832	844
NEPOOL capability responsibility[c]	826	871	911	915	932	952	986	1020	1038

Sources: Forecast, at I.2.35, I.4.111, I.5.11, and II.5.14-15; Responses to Staff Information Requests PL-1, PL-2 and PL-3.

Notes:
a All loads are given in MW.
b The System's summer peak loads are noncoincident, so the System's peak load does not equal the sum of the component loads.
The System's winter peak loads are coincident, but may not add due to rounding.
c Calculated by COM/Electric using NEPOOL methodology in accordance with the NEPOOL Agreement. See Response to Staff Information Request PL-3a.

COM/Electric's capacity situation is illustrated in Table S-2. The System states that it has approximately 1235 MW of existing generating capacity, of which 426 MW is sold to non-affiliated utilities under long-term contracts. To its 809 MW of net available capacity, the System forecasts the following additions (as shown in the Forecast Table E-17, at II.5.14-15):

- 40.5 MW from the Seabrook 1 nuclear power plant in 1986;
- 40 MW from the SEMASS waste-to-energy plant in 1987;
- various amount of hydroelectric power from the Power Authority of the State of New York ("PASNY"), growing from 0.6 MW in 1985 to 4.0 MW in 1993;
- 27.4 MW from the Boott Mills and Swift River hydro projects by 1985;
- 32.6 MW of power from unidentified small power producers or alternate energy sources by 1993.

Thus, COM/Electric forecasts having approximately 953 MW of net capacity available to meet its requirements in 1993 ---- almost 8 percent less than its forecasted capability responsibility for the summer of 1993 (1038 MW). Indeed, as Table S-2 shows, the System forecasts a capacity shortfall as early as 1991.

In light of this forecasted shortfall, <u>the Siting Council states that it is extremely concerned with the possible inadequacy of COM/Electric's supply plan over the forecast period</u>.

Moreover, the Siting Council must examine the validity of the System's assumptions for the timing and accessibility of forecasted capacity additions. If Seabrook 1 is cancelled or delayed, if the SEMASS plant is delayed beyond 1987, if power from PASNY or the other hydro projects is not available as anticipated, if the System falls short of its goals for acquisition of capacity from small power producers, if existing capacity is no longer available for any reason, or, if the System's load requirements increase faster than has been forecasted ---- then COM/Electric might face significant capacity shortfalls before 1991.

The System has excluded Seabrook 2 from its present supply plan due to concern about increases in projected costs, delays in scheduled completion, regulatory uncertainty, and consideration of cancellation by the joint owners (Forecast at II.5.12). The Siting Council agrees that this decision is prudent for planning purposes.

The Siting Council notes that cost increases, delays, and regulatory uncertainty are also relevant to the status of Seabrook 1. In April, 1984, the lead owner of the Seabrook project, Public Service Company of New Hampshire ("PSNH"), halted construction of the Seabrook project, because it was unable to obtain financing for the project.

TABLE S-2
COM/ELECTRIC GENERATING CAPACITY
Winter rated capacity in MW

Description	Fuel type	1985	1986	1987	1988	1989	1990	1991	1992	1993
Existing units										
	Nuclear	149.70	149.70	149.70	149.70	149.70	149.70	149.70	149.70	149.70
	Oil	868.87	868.87	868.87	868.87	868.87	868.87	868.87	868.87	868.87
	Oil/gas	154.40	154.40	154.40	154.40	154.40	154.40	154.40	154.40	154.40
	Diesel	13.75	13.75	13.75	13.75	13.75	13.75	13.75	13.75	13.75
	Jet fuel	48.00	48.00	48.00	48.00	48.00	48.00	48.00	48.00	48.00
Subtotal (winter-rated)		1234.72	1234.72	1234.72	1234.72	1234.72	1234.72	1234.72	1234.72	1234.72
New capacity										
Pt. Lepreau 1	Nuclear	25.00	25.00	25.00	25.00	25.00	25.00	0.00	0.00	0.00
Swift River	Hydro	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50
Boott Mills	Hydro	22.90	22.90	22.90	22.90	22.90	22.90	22.90	22.90	22.90
Unidentified	Alt.	0.00	0.00	7.60	12.60	17.60	22.60	27.60	32.60	32.60
Subtotal		52.40	52.40	60.00	65.00	70.00	75.00	55.00	60.00	60.00
Other capacity										
PASNY	Hydro	0.60	1.30	1.70	2.10	2.40	2.90	3.20	3.60	4.00
Seabrook 1	Nuclear	0.00	40.50	40.50	40.50	40.50	40.50	40.50	40.50	40.50
Seabrook 2	Nuclear	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SEMASS	Trash	0.00	0.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00
Subtotal		0.60	41.80	82.20	82.60	82.90	83.40	83.70	84.10	84.50
Capacity sales		-426.00	-426.00	-426.00	-426.00	-426.00	-426.00	-426.00	-426.00	-426.00
Net capacity		861.72	902.92	950.92	956.32	961.62	967.12	947.42	952.82	953.22
NEPOOL capability responsibility (summer)		826.00	871.00	911.00	915.00	932.00	952.00	986.00	1020.00	1038.00
Excess/shortage		35.72	31.92	39.92	41.32	29.62	15.12	-38.58	-67.18	-84.78
Contingencies										
Net capacity if:										
PASNY entitlements not included		861.12	901.62	949.22	954.22	959.22	964.22	944.22	949.22	949.22
Seabrook 1 cancelled		861.72	862.42	910.42	915.82	921.12	926.62	906.92	912.32	912.72
Seabrook 1 delay to 1987		861.72	862.42	950.92	956.32	961.62	967.12	947.42	952.82	953.22
SEMASS delayed to 1988		861.72	902.92	910.92	956.32	961.62	967.12	947.42	952.82	953.22
All contingencies		861.12	861.12	868.72	913.72	918.72	923.72	903.72	908.72	908.72
Excess/shortage if:										
PASNY entitlements not included		35.12	30.62	38.22	39.22	27.22	12.22	-41.78	-70.78	-88.78
Seabrook 1 cancelled		35.72	-8.58	-0.58	0.82	-10.88	-25.38	-79.08	-107.68	-125.28
Seabrook 1 delay to 1987		35.72	-8.58	39.92	41.32	29.62	15.12	-38.58	-67.18	-84.78
SEMASS delayed to 1988		35.72	31.92	-0.08	41.32	29.62	15.12	-38.58	-67.18	-84.78
All contingencies		35.12	-9.88	-42.28	-1.28	-13.28	-28.28	-82.28	-111.28	-129.28

Source: Forecast, at II.2.4, II.2.12, II.3.3, II.3.5, II.3.11, II.4.4, II.4.12-13, II.5.11-36; Responses to Staff Information Requests EG-1, EG-2, EG-4, EG-5, GPP-2, GPP-4, GPP-5, GPP-7, PL-3, PL-4, EG-7, EG-8, EG-9 and ASP-1.

Though construction of Seabrook 1 was resumed in July, 1984, construction of the Seabrook 2 was suspended indefinitely (Response to Staff Information Request GPP-2).

Further, the Siting Council must take notice that on April 4, 1985, the DPU issued its decision in the "generic" Seabrook 1 proceeding in No. 84-152. The DPU had instituted the preceeding ---- in response to a petition from Canal, and three other electric companies ---- to open a consolidated docket to review certain aspects of the Seabrook project.[20] The DPU concluded that the investor-owned utilities, including Canal, had failed to show requested financings were necessary, but that the utilities could attempt to proceed with financing in a manner which placed risk of continued participation in the project on Shareholders. Decision of April 4, 1985 at 71-72. The DPU also found the earliest reasonable completion date which could be projected was August 1988, with the possibility of a later date. Decision at 48-49. In view of the potential impacts of the DPU's Decision, the Siting Council must consider the impact of possible delays or cancellation of Seabrook 1 in its review of COM/Electric's supply plan.

Likewise, the Siting Council must review the System's assumption that the SEMASS plant will be in service by the summer of 1987. The System states that "[r]efuse contracts from surrounding municipalities and other sources are key to moving forward with the project" (Forecast at II.5.33). SEMASS needs contracts for 1200 tons per day of refuse to qualify for financing. Currently, SEMASS has long-term contracts for 948 tons per day of refuse, and expects to execute agreements for another 75 tons per day. Contracts for delivery of an additional 230 tons per day of refuse are being negotiated. The System is also negotiating with SEMASS to raise the Minimum Energy Price in the power purchase contract (Response to Staff Information Request GPP-4; Forecast at II.5.33).

The Siting Council notes that the System appears to be making efforts to complete the project. The Siting Council commends these efforts.

Nevertheless, construction of the facility, which is expected to take from 30 to 33 months (Id.), has not yet begun. The Siting Council must consider the possibility that the SEMASS facility will not be in service by the summer of 1987 as anticipated in the System's supply plan.

Regarding power from PASNY, the DPU is designated by law as Massachusetts' official bargaining agent in negotiations with the New York Power Authority (Ch. 604 of the Acts of 1935). In a letter dated January 2, 1985, the DPU stated its intent to allocate all of

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20 Specifically, the DPU investigated the estimated completion cost of Seabrook 1, including construction and financing costs; the estimated completion and commercial on-line dates; and the estimated operating characteristics of Seabrook 1.

Massachusetts' share of power from PASNY to municipal light departments ---- which precludes COM/Electric from purchasing any of this power. Though the DPU stated its intent "....to continue to review the matter as outstanding court and federal regulatory cases are resolved" (Response to Staff Information Request GPP-9), the Siting Council cannot assume that PASNY power will be available to the System as anticipated in its supply plan.[21]

Regarding the availability of existing capacity, the Siting Council notes that the System has in service one generating facility that dates from 1926 (Blackstone 4 -- 2.9 MW); two generating facilities from 1930 (Blackstone 1 -- 16.0 MW, and Blackstone 3 -- 2.9 MW); and two generating facilities from the 1940s (Kendall 1 -- 19.0 MW, 1949, and Cannon 1 -- 25.4 MW, 1947). (Response to Staff Information Request EG-4). Though COM/Electric states that none of these units have a scheduled retirement date at this time (Id), the Siting Council takes note that 66.2 MW of the System's capacity comes from generating facilities that are more than 35 years old.

Therefore, the Siting Council finds that there exists a significant possibility that the System's assumptions regarding planned additions of capacity may prove to be optimistic. Specifically, the Siting Council is concerned that COM/Electric may face a capacity shortfall earlier than 1991 ---- indeed, under certain circumstances, as shown in Table S-2, as early as 1986.

The Siting Council has stated this concern on earlier occasions. In its Decision on the System's previous forecast, In Re COM/Electric, 9 DOMSC 222, 270-291 (1984), the Siting Council described the System's capacity situation in detail and qualified its approval of the supply plan with four conditions:

1. That the Companies submit as part of their next filing a contingency plan for how they will meet their capacity responsibilities in the event that their proposed supply additions (especially Seabrook Units 1 and 2, SEMASS, and Hydro-Quebec) do not come on line on their currently scheduled dates.

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21 When asked during discovery to describe the nature of the legal, regulatory, contractual and construction actions that must occur before PASNY could deliver power to Massachusetts (Staff Information Request GPP-5d(1)), COM/Electric neither described the nature of the DPU's authority to allocate power among Massachusetts utilities (though that decision was pending), nor discussed the issue of "municipal preference." The Siting Council considers these omissions to be serious ones, as they evidence the System's failure to analyze completely the status of forecasted additions of capacity in its discovery responses.

2. That the Companies submit as part of their next filing a supply plan which is sufficient to cover projected peak demand and resources [sic] for <u>all</u> forecast years.

3. That the Companies' staff meet within 90 days with the staffs of the Council and the Executive Office of Energy Resources to: further develop and refine the Companies' plans to acquire either energy or capacity generated by renewable resources or co-generation; and discuss the range of load management techniques available to the Companies, as well as the Companies' plans for monitoring and analyzing the costs and effectiveness of alternative load management and conservation strategies.

4. That the Companies perform a cost-benefit analysis of all of their projected supply additions (including load management strategies, renewable resource projects, conservation, and cogeneration options) to show which of their programs will be most cost-effective over the life of the investment.

COM/Electric has responded satisfactorily to Conditions 3 and 4 in this filing. In July, 1983, representatives of the System met with the staffs of the Siting Council and the Executive Office of Energy Resources ("EOER") in compliance with Condition 3 to discuss the roles of alternative energy resources and load management in the overall supply mix. At that time, COM/Electric also presented its <u>Interim Report on Conservation Planning and Load Management</u> ("Interim Report"). The System has submitted extensive documentation of its efforts to comply with Condition 4, including a description of its implementation of the Load Management Strategy Testing Model ("LMSTM") and much information on its conservation programs. Indeed, COM/Electric's efforts to obtain power from small power producers and to use LMSTM to investigate its potential for load management are two bright spots in an otherwise bleak supply picture.

On the other hand, the Siting Council is not satisfied with COM/Electric's response to Conditions 1 and 2. The System's own demand and supply assumptions project a capacity shortfall by 1991 ---- just six years away. Yet, in its initial filing, COM/Electric neither submitted a supply plan sufficient to cover projected peak demand and reserve requirements, as required by Condition 2, nor submitted a contingency plan, as required by Condition 1. In view of these omissions, and the seriousness of the System's capacity situation, the Siting Council cannot conclude on the basis of the evidence before it that the System is able to provide sufficient capacity to meet its requirements (See section III. A., <u>supra</u>).

Therefore, the Siting Council hereby REJECTS COM/Electric's supply plan for its failure to meet the Siting Council's standards for adequacy, and for its failure to comply with Conditions to the approval of the previous supply plan.

Further, the Siting Council hereby Orders the System to provide in its next filing a supply plan that is sufficient to cover projected peak demand and reserve requirements for all forecast years. The System shall supply in its initial filing its projections of capability responsibility to NEPOOL for each summer and winter over the forecast period, and shall clearly identify the sources of capacity that it assumes will be available to meet its capability responsibility in each season. The information supplied shall be compatible with that used in the System's own generation expansion and production cost simulations. This Condition is affixed hereto as Condition S-1.

In the sections that follow, the Siting Council reviews in more detail the System's capacity options, policies toward cogenerators and small power producers, load management programs, and consideration of construction of new generating facilities.

1. Capacity Options

As stated earlier, COM/Electric did not comply with the Siting Council's Order requiring submission in its initial filing of a contingency plan for how the System would meet its capacity requirements in the event that proposed supply additions did not come on line as scheduled.

Still, COM/Electric did provide some information on its capacity options in its initial forecast filing. Further information, including a brief response to the Siting Council's Condition on contingency planning, was provided during the discovery process (Forecast II.5.11-13; Response to Staff Information Request GPP-2(b)2).

In the long run, COM/Electric states that it will seek out capacity "from neighboring utilities or Canadian utilities within the limitations of practical transmission to our system" (Response to Staff Information Request GPP-2(b)2). Canadian sources mentioned by the System include capacity from a transmission entitlement related to its participation in Phase 1 of the Hydro Quebec project (28 MW), power purchases from the Point Lepreau 2 nuclear power plant proposed to be constructed in New Brunswick (up to 50 MW), and capacity from Phase 2 of the Hydro Quebec project (estimated at 58 MW). Should Point Lepreau 2 not be built, there exists some possibility that the System will be able to renew its contract for 25 MW of capacity from Point Lepreau 1 after the existing contract expires in 1991. Although the System does not specify the nature of individual purchases from neighboring utilities, it states that "COM/Electric has continuing opportunities to contract to purchase and sell capacity with other NEPOOL participants" (Forecast at II.5.11; Responses to Staff Information Requests EG-8 and GPP-8).

In the short run, if Seabrook 1 is delayed or cancelled, the System states that it has "limited options" (Response to Staff Information Request GPP-2(b)2). COM/Electric restates its commitment to reduce its system peak load growth through conservation and load management programs, and to obtain power from alternate resources or from other NEPOOL members. In addition, the System is considering the installation of gas turbines, which have an estimated lead time of five years, as a short-term measure (see Sections III.B.2-4, infra, for reviews of the System's policies toward power from alternate resources, load management, and new generation).

The Siting Council notes that each of these options is subject to considerable uncertainty.

Though COM/Electric has actively expressed its interest in acquiring capacity from Point Lepreau 2, negotiations for a power purchase contract are at an early stage. Even if a decision to build the plant is reached by mid-1985, the New Brunswick Electric Power Commission estimates that the plant could not be constructed and in-service until at least the summer of 1991. Additionally, COM/Electric expects that "transmission capacity will have to be increased for New England to realize the full potential output from the proposed Point Lepreau Unit II" (Response to Staff Information Request GPP-3).

The issue of capacity credit from the Hydro Quebec projects is still the subject of extensive negotiations. COM/Electric states that it has "... supported options which maximize the capacity credit for participants" (Id). Though commending this position, the Siting Council recognizes that numerous negotiations and regulatory approvals remain before the determination of the capacity benefits of these projects is finalized, or indeed, before the status of Phase 2 of the Hydro-Quebec project is determined.

Regarding the risks of reliance on NEPOOL purchases, the System states (Forecast at I.5.11):

> ... While this option affords maximum flexibility, it is obvious that not all NEPOOL participants can engage in such behavior indefinitely since available capacity in the Pool would soon be exhausted. Further, this is viewed as a limited option since NEPOOL participants that have capacity to sell will offer their higher cost oil-fired generation and retain their nuclear and coal capacity for their own system use.

The Siting Council generally agrees with this assessment. The Siting Council adds that, because of the uneven distribution of capacity among NEPOOL member utilities, cancellation of Seabrook 1 might require several Massachusetts utilities to seek replacement capacity from the Pool simultaneously, thereby exacerbating the risks of reliance on NEPOOL purchases. See In Re EUA, 11 DOMSC 61, 90 (1984); In Re Fitchburg, 11 DOMSC 29, 54 (1984).

In view of these uncertainties, the Siting Council understands the System's reluctance to specify its precise plans for supply additions over the forecast period. The Siting Council recognizes that COM/Electric faces difficult trade-offs between securing adequate capacity and maintaining the flexibility to optimize the diversity and cost of its supply plan. A premature commitment to a single course of action might needlessly sacrifice flexibility or result in unnecessary costs and risks. Moreover, such a disclosure might compromise the System's ability to negotiate with suppliers of capacity.

Nevertheless, the Siting Council requires that supply plans explicitly address available capacity options and trade-offs in a reviewable fashion. True, COM/Electric's supply plan lists possible supply options, but it does not examine systematically how the lead times and magnitudes of these options interact with its capacity needs over time. Nowhere in its supply plan does COM/Electric describe the interactions between the timing and magnitude of its capacity shortfalls, and its need for purchases from NEPOOL for each forecast year. Nowhere does it examine quantitatively the sensitivity of these purchases to assumed annual peak reductions from conservation or load management programs, to delays of the Seabrook and SEMASS projects, to the possible cancellation of Seabrook 1, to variations in the amount of capacity available from small power producers, or to changes in the rate of demand growth in its service territory or in New England.

Without such an analysis, the Siting Council cannot find that the System is taking all necessary steps to insure that its supply plan meets mandated standards for adequacy, diversity and cost. The need for this analysis is highlighted by the System's forecasted long-term capacity shortfall ---- identified in the previous filing and exacerbated in the current filing ---- and by the Siting Council's finding that the System's assumptions regarding planned additions of capacity may prove to be optimistic. Indeed, the System's failure to produce a contingency analysis in response to the Siting Council's Order is in itself grounds for rejection of the System's supply plan.

Therefore, the Siting Council hereby ORDERS COM/Electric to present in its next filing a complete sensitivity analysis of the magnitude and timing of its planned additions and capacity needs under a reasonable set of contingencies in its next filing. The Siting Council hereby informs the System that presentation of an acceptable sensitivity analysis will be a prerequisite to approval of future supply plans or of future applications to construct new generation or transmission facilities under the Siting Council's jurisdiction. The Siting Council staff is available upon request for technical assistance and further clarification of the terms of this Condition, affixed hereto as Condition S-2.

The Siting Council encourages the Companies to file a new supply plan within six months, as afforded under Mass. Gen. Laws Ann. Ch. 164, Sec. 69J. The Council staff commits itself to working with the Company in advance of such filing to help ensure that the elements of the filing are adequate. Additionally, the Council staff commits itself to a timely review of a filed supply plan such that the Staff's review does not stand in the way of the construction of any transmission line that the Council has determined is needed for reliability purposes.

2. Cogeneration and Alternate Energy Sources

In its supply plan, COM/Electric presents an aggressive policy in pursuit of capacity and energy from alternate resources. The filing includes a target for capacity from alternate resources by 1993, adoption of innovative contracting policies, and descriptions of projects in progress.

COM/Electric has established a target of 100 MW of capacity to be supplied from alternate resources by 1993. This capacity target is integrated into the Comparison of Resources and Requirements (Table E-17) of the System's supply plan, and into Table S-2 of this Decision. The System already has contracts for approximately 70 MW of such capacity. Though almost 90 percent of the System's capacity under contract is from two facilities (SEMASS and Boott Mills Hydro), and though the System does not mention other alternate energy projects of comparable size, the System is confident that sufficient numbers of smaller projects will materialize to achieve its goal (Forecast at II.5.12, II.5.14-15, and II.5.28-29; Response to Staff Information Request ASP-2).

The Siting Council is pleased that COM/Electric has made a strong commitment to contract for capacity from alternate energy sources. By setting an ambitious capacity target and integrating that target into its supply plan, the System appears to be responding appropriately to its capacity situation and its need to obtain diverse and cost-effective sources of energy. The Siting Council encourages the System to continue its efforts to obtain capacity from these sources and to adjust its capacity target as circumstances warrant.

To achieve the target, COM/Electric has adopted innovative contracting procedures. The System routinely offers floor prices and energy cost banking arrangements to potential developers. These policies, along with the System's avoided cost rates, have been successful in attracting project proposals from developers, as evidenced by the large number of projects in progress that COM/Electric describes in its forecast (Id).

Again, the Siting Council states its approval of the System's policies for pursuing capacity and energy from alternate sources. These policies demonstrate the System's sensitivity to the needs of project developers, and add credibility to the System's whole approach to supply planning.

COM/Electric is also considering cogeneration opportunities. The System is investigating the possible installation of gas expander turbines at three natural gas pressure reduction stations. It has helped one customer to install a 60 KW modular cogeneration unit, and has surveyed the interest of its largest industrial customers in self-generation. Moreover, the System is attempting to acquire interruptible generation from customers that own back-up generation and would be willing to dispatch it on request to meet peak load. Finally, the System states its willingness to negotiate contracts with any cogenerators (Forecast at II.5.35 and III.11-14; Response to Staff Information Requests GPP-7, ASP-1 and ASP-2). The Siting Council encourages the System to continue these efforts.

However, COM/Electric has not formally followed up its survey of large industrial customers interested in self-generation with offers of technical assistance or incentives, nor has it estimated the potential for capacity savings from these customers. Likewise, the System has not actively promoted small modular cogeneration units. COM/Electric states that it "purchased no electricity from cogeneration sources, industrial or commercial in 1983 and at this time does not foresee any such purchases," and that "the demand forecast does not include any load reductions due to customer generation" (Response to Staff Information Request ASP-1).

The Siting Council is concerned that the System's passive approach to cogeneration is inconsistent with its pending capacity shortfalls and the need for diversity of its fuel sources. Indeed, the System's passive approach to cogeneration appears to be inconsistent with its aggressive and laudatory approach to development of alternate energy projects. In view of the potential benefits, the Siting Council expects COM/Electric to actively encourage customers that are able to do so to pursue cogeneration options, and to estimate the potential for energy and capacity from these customers.

Therefore, the Siting Council hereby ORDERS the System in its next filing to forecast its potential for acquisition of capacity and energy from cogeneration, and its potential for peak reduction due to customer self-generation. The System shall survey cogeneration potential among its large industrial customers that have already indicated an interest in self-generation, as well as those smaller industrial and commercial customers that may be attractive candidates for modular cogeneration units. The Siting Council further encourages the System to commence a program by which these customers are routinely provided with information on cogeneration technology and economics, including the emerging modular units, by which these customers are routinely surveyed for their interest and response, and by which the System provides these interested customers with additional encouragement and incentives. The System shall document its efforts to comply with this Condition, affixed hereto as Condition S-3, in its next filing.

3. Load Management Programs

In the current filing, COM/Electric responds in detail to the Siting Council's Order requiring a cost-benefit analysis of all projected supply additions. The System is implementing a new analytical model, the Load Management Strategy Testing Model ("LMSTM"),[22] to evaluate the costs and benefits of its load management programs on a basis consistent with its evaluation of other capacity expansion strategies. In its filing, COM/Electric documents the structure of LMSTM, presents preliminary results, and describes the System's plans for its continued use. The filing also documents the status of COM/Electric's existing load management programs.

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22 COM/Electric is one of four utilities nationwide to participate in the implementation phase of LMSTM. Development of LMSTM is sponsored by the Electric Power Research Institute.

LMSTM is an "integrated corporate planning model to evaluate supply options" (Forecast at III.15). The model simulates the impacts of individual load management programs on the System's demand forecast, power production costs, financial requirements, and rate design strategy. As inputs, LMSTM uses: the Cambridge and Commonwealth Energy Models and Hourly Load Models, for demand information; NEPOOL Generation Task Force ("GTF") assumptions for construction costs of conventional generating facilities; forecasts of energy prices, GNP, and relevant financial and operating data; and the System's Cost of Service studies, for rate design information (Response to Staff Information Request LM-1).

One output of LMSTM is an analysis of the contribution to the System's peak load from various end uses and customer types. COM/Electric used LMSTM to produce hourly load shapes for typical summer and winter peak days, then calibrated the load shapes through comparisons with actual data and with output from its hourly load models. COM/Electric used the calibrated model to forecast the sources of peak demand over the forecast period.

Table S-3 presents the results of several forecasts of contribution to peak by end use. As the table shows, Commonwealth estimates that residential and commercial base load use each account for approximately 40 percent of its peak load, while Cambridge estimates that its commercial and industrial sectors account for more than 80 percent of its peak load. Peak losses in the transmission and distribution system are also significant. The major sources of increases in Commonwealth's peak load are air conditioning in residences, homes, and stores; lighting in homes and stores; and miscellaneous residential baseload. In addition, Commonwealth forecasts significant peak load growth for industrial SIC codes 20 (food), 34 (fabricated metals), 36 (electrical machinery), 38 (instruments) and 39 (miscellaneous). Cambridge forecasts that almost all of its growth in peak demand will occur in the commercial and industrial sectors.

The Siting Council is extremely pleased that COM/Electric has begun to acquire the capability to disaggregate its forecast of peak growth. The System is now positioned to estimate with some measure of confidence the full potential for load management within its major end use and customer groups.

The Siting Council notes that several features of this new capability may require further refinements. The largest single end use is "miscellaneous baseload" for residential non-heating customers, a category that lumps together the contributions of most residential appliances (e.g., refrigerators). COM/Electric may find it useful to investigate the role of individual appliances or groups of appliances within this category. Similarly, the System may find it fruitful to analyze the composition of peak loads in Cambridge beyond the four general rate classifications presented in this filing, especially within Cambridge's large commercial sector.

TABLE 5-3
COM/ELECTRIC SOURCES OF PEAK LOAD

Year	1982	1988	1993	Changes*	Changes
Season	summer	summer	summer	82-88	88-93
Hour	1600	1700	1700		
Commonwealth	354.7	431.8	483.8	77.1	52.0
Residential Nonheating	142.0	185.3	204.4	43.3	19.1
Elec water heating	1.8	2.4	2.5	0.6	0.1
Room A/C	39.4	41.2	51.9	1.8	10.7
Central A/C	7.0	6.9	8.5	-0.1	1.6
Second homes	20.5	29.2	31.0	8.7	1.8
Lighting	3.8	5.9	6.3	2.1	0.4
Misc. baseload	69.5	99.7	104.2	30.2	4.5
Residential heating	14.3	21.1	26.4	6.8	5.3
Elec water heating	2.3	3.6	4.2	1.3	0.6
Room A/C	3.5	5.0	7.5	1.5	2.5
Central A/C	0.7	0.8	1.1	0.1	0.3
Lighting	0.4	0.8	0.9	0.4	0.1
Misc. baseload	7.4	10.9	12.7	3.5	1.8
Commercial nonheating	144.4	165.2	184.4	20.8	19.2
Stores baseload	9.1	9.4	10.2	0.3	0.8
Offices baseload	11.4	13.8	15.0	2.4	1.2
Stores lighting	36.7	37.6	40.7	0.9	3.1
Offices lighting	45.2	55.1	59.9	9.9	4.8
Street lighting	0.0	0.0	0.0	0.0	0.0
Canal service	1.1	1.0	1.0	-0.1	0.0
Stores A/C	26.7	24.1	29.9	-2.6	5.8
Offices A/C	14.2	14.0	17.6	-0.2	3.6
AT&T	0.0	10.2	10.1	10.2	-0.1
Commercial heating	2.8	2.6	2.9	-0.2	0.3
Stores baseload	0.1	0.1	0.1	0.0	0.0
Offices baseload	0.1	0.1	0.1	0.0	0.0
Stores lighting	0.3	0.4	0.4	0.1	0.0
Offices lighting	0.4	0.5	0.6	0.1	0.1
Stores A/C	0.5	0.4	0.5	-0.1	0.1
Offices A/C	0.3	0.2	0.3	-0.1	0.1
Electric schools	1.1	0.9	0.9	-0.2	0.0
Industrial SIC groups	41.8	48.7	56.8	6.9	8.1
Otis Air Force Base	9.4	8.9	8.9	-0.5	0.0
Cambridge	199.0	192.3	203.4	-6.7	11.1
Residential	22.7	23.9	24.2	1.2	0.3
Commercl/Industrl	157.9	157.1	167.5	-0.8	10.4
Belmont	18.4	11.3	11.7	-7.1	0.4
Trans & Dist	53.4	72.6	80.2	19.2	7.6
Off-peak WH	18.8	21.0	23.9	2.2	2.9
COM/Elec system total	625.9	717.7	791.3	91.8	73.6

Source: Forecast, at III.32-37; Response to Staff Information Request LM-3.

Note: * Some of the changes from 1982 to 1988 result from the switch in the peak hour from 1600 to 1700.

Generally, the accuracy of LMSTM appears to be constrained by the quality of the available data and the accuracy of the System's demand models. Still, the preliminary results seem to indicate that LMSTM can prove to be an extremely useful planning tool, and the Siting Council encourages its continued development.

A second use for LMSTM is analysis of the potential capacity, cost and benefits of specific load management and conservation programs. COM/Electric describes the results of its most recent analyses in its Demand Side Planning Report: Cost/Benefit Analysis of Conservation and Load Management Options ("C/B Report").

The C/B Report estimates total potential demand savings from five programs of at least 33.5 MW by 1995,[23] and mentions an additional 15 MW of potential interruptible load from industrial customers with on-site generating capacity. Commercial lighting and direct load control of existing water heaters are two measures singled out as major sources of demand savings, but all five of the programs cited have benefits that exceed program costs. The cost/benefit ratios of these projects are not highly sensitive to customer participation rates. The C/B Report also addresses the impact of the addition of new electric heating, electric storage heat and heat pump customers on winter peak growth, and the conditions under which the System might become winter-peaking (C/B Report at 21, 28-31).

The C/B Report recommends that the System accelerate its existing water heater wrap program, encourage commercial lighting conservation, undertake a pilot direct load control study, and monitor the electric space heating issue in order to use load management to further reduce peak loads (C/B Report at 31). These measures will augment the load management programs currently in place, which reduced COM/Electric's 1983 peak by 15.4 MW[24] (Forecast at III.5).

The Siting Council notes that the results presented in the C/B Report are preliminary in nature. Only five demand-side planning options were examined. As the System itself states, "[u]ltimately, many more options should be screened and, if found to be feasible, evaluated in detail" (C/B Report at 10). Further, the analysis should state clearly the basis for selecting specific levels of investment in specific demand-side options, and should identify who pays the costs and

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23 This estimate includes 8.5 MW from commercial lighting programs, 10.8 MW from timer-controlled water heaters, 2.9 MW from space heating class water heaters, 1.3 MW from regular residential class water heaters, and 0.4 MW from water heater wraps. It assumes low customer penetration rates. C/B Report, at 21.

24 This estimate includes 7.2 MW from off-peak water heating, 4.1 MW from power factor improvements, 2.8 MW potential from interruptible rates, 1.0 MW from low loss transformers, and 0.25 MW from water heater wraps. Forecast, at III.3 and III.5.

who receives the benefits (e.g., ratepayers, shareholders, society) of the programs. To the extent possible, the System should incorporate data from actual experience in program implementation. The Siting Council anxiously awaits further results from the System in these areas.

Nevertheless, the Siting Council is quite pleased with the extent of COM/Electric's good faith efforts to comply with Condition 4. The care with which the System is analyzing its load management options, and the commitment of resources to use LMSTM to evaluate its capacity benefits and costs, show that the System is beginning to consider load management programs on a par with other capacity alternatives. Therefore, the Siting Council states that the System has complied with the intent of Condition 4 as regards load management. The Siting Council requests that the System continue its efforts to refine its use of LMSTM and document its progress in its next filing.

The C/B Report states that load management programs are "important strategic alternatives for reducing the anticipated capacity shortfall" (C/B Report at 3). In light of the System's capacity situation, the Siting Council encourages the System to implement its load management programs as quickly as resources and prudent planning allow. The Siting Council requests that the System provide in its next filing a target schedule of annual peak reductions (in MW) due to load management programs over the forecast period. The schedule should be similar in nature to the targets presented in the instant filing for capacity from renewable resources as part of Table E-17.

Finally, the Siting Council agrees with COM/Electric's statement that "[t]he key to successful implementation of a demand-side planning program is a flexible implementation plan that addresses the uniqueness of various program options" (Response to Staff Information Request CP-4). The Siting Council encourages the System to adopt implementation approaches appropriate to its capacity needs. The Siting Council notes that direct utility action and provision of services might be required in those cases when utility actions are required for successful program operation (e.g., direct load control, interruptible rates), when market incentives do not coincide with the System's load objectives (e.g., third-party development of new commercial facilities), or when decisions that affect peak load additions can be influenced only within a limited time frame (e.g., consumer purchases of durable appliances, new building design). The Siting Council encourages the System to provide direct services and undertake direct action as appropriate, and not to rely too heavily on any individual strategy for program implementation.

4. New Construction

In the instant filing, COM/Electric does not request approval for construction of any new facilities. However, COM/Electric states in its forecast that it is investigating the feasibility of constructing new generation in order to meet its projected capacity shortfalls. Types of facilities under consideration include coal-fired capacity, conventional gas turbines, and combined-cycle gas turbines.

The System is investigating the feasibility of constructing a 600 MW coal-fired plant, possibly on a site adjacent to existing oil-fired units (Canal 1 and 2) in Sandwich, Mass. A preliminary study estimates the site acreage requirements for two 600 MW coal-fired units at 55 acres, or 27.5 acres per unit. Depending on the site, the facility might occupy as much as 40 acres. In addition, the study identified two major problems requiring further investigation ---- a disposal site for sludge from the scrubbers that would remove sulphur from the facility's exhaust stack, and a source of fresh make-up water. Using estimates provided by the Generation Task Force of the NEPOOL Planning Staff ("GTF assumptions"), COM/Electric uses a 1984 capital cost for the coal facility of $1484 per KW for planning purposes, which comes to $890 million for a 600 MW plant. COM/Electric assumes that construction requires ten years of lead time, also consistent with GTF assumptions. COM/Electric states that it would need to seek participation by other utilities in a unit of such size (Forecast at II.5.13; Response to Staff Information Request GPP-6a).

COM/Electric is also investigating the feasibility of constructing a 107 MW combined cycle gas turbine at an unidentified site. The System estimates the land requirement as at least 5.5 acres. The facility requires access to a supply of high pressure natural gas. Consistent with the GTF assumptions, COM/Electric uses a 1984 capital cost of $691 per KW for planning purposes, which comes to $74 million for a 107 MW plant. COM/Electric assumes that construction of a combined cycle gas turbine facility requires eight years of lead time. The System can reduce the lead time required to obtain capacity from the facility by installing the gas turbine first and adding the steam cycle at a later date as required (Forecast at II.5.12; Response to Staff Information Request GPP-6b).

The Siting Council appreciates the System's descriptions of its options for construction of new capacity. The Siting Council encourages the System to continue its efforts to investigate these options as appropriate to its capacity needs.

COM/Electric is reminded that applications to the Siting Council for construction of new generation facilities should include descriptions of "alternate methods of generation or sources of power, [and the] effect if the specified generating facility were not constructed", Rule 64.B(5)(i). The Siting Council interprets this to mean that a complete application for construction of a new generating facility should include descriptions of the utility's opportunities to obtain power from alternative energy sources, cogeneration, load management and conservation programs, power purchase contracts, and growth control programs, along with an analysis of the magnitude and timing of the utility's capacity needs under various contingencies (see section III.A.1, supra). To be approved, the Siting Council must find that the utility's proposal is superior to the alternatives, is consistent with "current health, environmental protection, and resource use and development policies as developed by the commonwealth", and is consistent with the mandate "to provide a necessary power supply for the commonwealth with a minimum impact on the environment at the lowest possible cost", Mass. Gen. Law. Ann., ch.164, sec. 69J.

In comparing the utility's proposal with the alternatives, the Siting Council will analyze whether the utility can obtain comparable capacity and energy benefits through comparable investment in alternatives during a comparable lead time. Conditions S-1, S-2, and S-3 to this Decision, as well as Conditions S-1, S-2, S-3, and S-4 to the previous Decision, are intended to guide the System's capabilities toward compliance with this standard. The Siting Council hopes that this statement clarifies its standards for proposals to build new generating facilities and reduces the uncertainty surrounding the requirements for such applications.

The Siting Council is encouraged by COM/Electric's progress toward meeting this standard, particularly in the System's attempts to obtain capacity from alternate energy sources and to analyze its potential for load management with LMSTM. The Siting Council expects the System to continue its efforts to perform cost/benefit analyses of its projected supply additions, and therefore retains Condition S-4 to the previous Decision as a Condition to the approval of this supply plan.

C. Diversity of the Supply Plan

COM/Electric depends heavily on oil to produce electricity. As Table S-4 shows, nearly two thirds of the electrical energy that the System forecasts to use in 1985 will be produced from fuel oil. Moreover, 72 percent of the summer-rated capacity of the System's existing units is fired by residual fuel oil, 13 percent is fired by either oil or natural gas, 4 percent is fired by jet fuel, and 1 percent is fired by diesel fuel oil (see Table S-2, supra).

On the other hand, the COM/Electric supply plan indicates that the System is moving actively to reduce its oil dependence. The System estimates that the share of electrical energy to be produced from oil will drop to 55 percent by 1993. This supply plan assumes that oil will be displaced by the addition of nuclear energy from Seabrook 1, hydroelectric energy from Hydro Quebec, PASNY, and numerous small power producers, and energy from various cogeneration and alternative energy sources, including the SEMASS waste-to-energy plant. The System anticipates that the Hydro Quebec project alone will displace about 120 GWH per year from 1987-1991, and about 277 GWH per year starting in 1992 (Response to Staff Information Request GPP-1). The estimates do not account for further displacement of oil through utility conservation programs or through the addition of new generation capacity that uses a fuel other than oil, which would decrease the System's dependence on oil below the levels forecasted in Table S-4.

The Siting Council commends COM/Electric's recognition of its heavy dependence on oil-fired generation and its attempts to diversify its fuel mix. The Siting Council encourages the System to continue its diversification efforts especially in light of possible contingencies (See section III.B, supra).

TABLE S-4
Forecast of Electrical Energy by Fuel Type[a]
(GWH)

	1985	(%)	1989	(%)	1993	(%)
Fuel Oil	2563	(65.2)	2324	(53.9)	2511	(54.5)
Natural gas[b]	156	(4.0)	117	(2.7)	77	(1.7)
Uranium	1114	(28.3)	1365	(31.7)	1210	(26.3)
Hydro	99	(2.5)	233	(5.4)	400	(8.7)
Other	0	(0.0)	271	(6.3)	411	(8.9)
Total	3932	(100)	4310	(100)	4609	(100)

Source: Response to Staff Information Request EG-6.

Notes: [a] Estimates are based on a simulated own load dispatch and do not account for power exchanges through NEPOOL.

[b] Estimates based on 1984 usage data.

D. Conservation Programs

COM/Electric presents detailed information on its conservation programs in its filing. The System has submitted descriptions of the programs it is currently implementing; data on program costs, energy savings and participation rates; and sample materials from its information programs. In addition, the System evaluates the impact of conservation programs on its peak demand in its descriptions of LMSTM and load management programs (see section III.A.3., supra).

COM/Electric states that its conservation programs saved approximately 52 million KWH of energy in 1983.

Most of its savings result from the System's efforts to reduce energy losses during the transmission and distribution of electricity ---- 24.2 million KWH from insulating fuel oil storage tanks at generating plants, 14.5 million KWH from a power factor improvement program, 3.6 million KWH from a program to reduce the System's own use of electricity for lighting, 3 million KWH from purchases of low loss transformers, and 2.7 million KWH through reductions in transmission line losses.

The remaining 4 million KWH are attributable to the Energy Management Plan ("EMP") that the System is implementing in order to assist its customers with their conservation efforts. Programs being implemented as part of the EMP include: a Water Heater Wrap and Weatherization Program, to provide "low-cost/no cost" conservation services; a Weatherization Assistance program, to distribute conservation kits to the System's low-income customers; a rebate program, to encourage customers with electric heat to install conservation measures recommended by a Mass-Save audit; a program to provide energy audits to commercial, industrial and governmental facilities; and an extensive energy information program (Forecast, at III.1; Response to Staff Information Request LM-4a).

The Siting Council is pleased that COM/Electric is beginning to implement a set of conservation programs. The Siting Council encourages the System to continue to obtain benefits through implementation of conservation programs as quickly as resources and planning permit. Specifically, the Siting Council encourages COM/Electric to expand its programs for assisting its customers with their conservation efforts in an appropriate fashion.

To augment its program descriptions, COM/Electric presents an impressive array of summary statistics on its conservation programs. For its water heating wrap and weatherization program, the System presents data on the number and cost of measures installed disaggregated by measure and fuel type (Forecast, at III.9 and Appendix A). For its audit program, the System presents data on the estimates of KWH and dollars saved from each measure, disaggregated by facility type (Forecast, at Appendix B). Though the System did not use these data in its demand forecast, it did use the data to analyze the costs and benefits of its existing conservation programs and to modify and further develop its programs (Response to Information Request CP-3).

Again, the Siting Council is pleased that the System is monitoring its conservation efforts so carefully. The Siting Council encourages the System to continue these efforts. In addition, the Siting Council encourages the System to augment its collection of audit data by collecting actual usage data, and to use these data to improve its demand forecasting as appropriate. Of particular interest to the Siting Council would be estimates of the System's total conservation potential for its ratepayers and the rate at which the System might implement programs to achieve this potential.

Though COM/Electric presents substantial data regarding its energy conservation program costs and predicted savings, it does not document the criteria that it uses to select levels of investment in each program. Presumably, the System is in the process of refining its cost/benefit analysis. The Siting Council requests that the System include conservation programs in its cost-benefit analysis of projected supply additions, and that the System document the results in its next filing as part of its compliance with Condition 4.

IV. DECISION AND ORDER

The Siting Council hereby REJECTS, in part, and ACCEPTS, in part, subject to Conditions, the Combined First and Second Supplements to the Second Long-Range Forecast of Electric Power Needs and Requirements of the Cambridge Electric Light, Canal Electric and Commonwealth Electric Companies. As discussed herein, the Siting APPROVES unconditionally the demand portion of the Forecast, and REJECTS and imposes four CONDITIONS on the supply portion. In the next supplement, to be filed on or before February 1, 1986, the Siting Council hereby ORDERS:

S-1. That the System provide a supply plan that is sufficient to cover projected peak demand and reserve requirements for <u>all</u> forecast years, as described herein;

S-2. That the System present a complete sensitivity analysis of the magnitude and timing of its capacity needs under a reasonable set contingencies;

S-3. That the System forecast its potential for acquisition of capacity and energy from cogeneration;

S-4. That the System continue its efforts to perform a cost-benefit analysis of all of its projected supply additions and conservation programs, and document its results in reviewable form.

James G. White, Jr.
James G. White, Jr., Esq.
Hearing Officer

On the Decision:
George H. Aronson

Unanimously APPROVED by the Energy Facilities Siting Council on April 25, 1985, by those members and designees present and voting: Chairperson Sharon M. Pollard (Secretary of Energy Resources); Joellen D'Esti (for Secretary of Economic Affairs, Evelyn F. Murphy); Sarah Wald (for Secretary of Consumer Affairs, Paul W. Gold); Stephen Roop (for Secretary of Environmental Affairs, James S. Hoyte); Robert W. Gillette (Public Environmental Member); Joseph W. Joyce (Public Labor Member). Ineligible to vote - Dennis J. LaCroix (Public Gas Member).

5/3/85
Date

Sharon M. Pollard
Sharon M. Pollard
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of the Bay State Gas Company for Approval of the First Supplement to the Second Long-Range Forecast of Gas Requirements and Resources, 1983-1988	Docket No. 83-13

FINAL DECISION

James G. White, Jr.
Hearing Officer

On the Decision:

Juanita M. Haydel

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The Energy Facilities Siting Council APPROVES subject to CONDITIONS the First Supplement to the Second Long-Range Forecast of natural gas requirements and resources of Bay State Gas Company ("Bay State" or "Company")

At the outset, the Siting Council recognizes that this decision contains language which is highly critical of the Company's Forecast. Therefore, the Council wants to indicate the specific reasons for approval of this Forecast.

First, the Council recognizes that in the past it has not reviewed gas company forecasts with the rigor applied to electric forecasts.

In the Siting Council's view, the state of the art of forecasting gas sendout requirements is comparatively underdeveloped, perhaps resulting in part from the fact that the level of available gas supplies served to form a constraint on growth, thereby reducing the importance of forecasting. In a senario of constrained growth, and perhaps in the absence of persistent guidance from the Council itself, gas company forecast techniques generally did not improve.

The Siting Council believes the sendout forecasting will assume greater significance in the emerging, more-competitive natural gas markets. This decision exemplifies the type of review the Council will attempt to bring to bear in the future.

Although critical of some of Bay State's current forecasting methods, the criticisms might as easily be applied to some other gas companies. Thus, the Siting Council's present decision is intended to provide notice of the scope of future proceedings.

Indeed, the Council itself has implicitly condoned the practice of requiring appropriate documentation and explanation through discovery responses rather than in the initial filings. In this proceeding, Bay State quite possibly might have been able to assuage some of the criticism through further interaction with the Council.

As indicated, however, in the Procedural Order of April 11, 1985, this proceeding has been subject to delay for several reasons. That Procedural Order indicated that the preferred path was to terminate this proceeding thereby affording the Company with the guidance contained herein.

Accordingly, the Council APPROVES the current Supplement.

I. Introduction

A. History of the Proceeding

A succinct view of this proceeding, hardly a model of administrative efficiency, is that the Siting Council's review was entangled for the first six months in procedural disputes between Bay State and the New England Fuel Institute, Inc. ("NEFI"). Thereafter, the Siting Council's review was delayed due to substitution of a new Hearing Officer and a change of personnel in the Siting Council's own Staff. Accordingly, the recent Procedural Order of April 11, 1985, for the reasons set forth therein, provided that this Decision would be issued without additional proceedings.

Bay State filed the current Supplement on November 10, 1983. Bay State supplemented its filing on November 30, and December 12, 1983 with certain Siting Council Tables. In accordance with the directions of the Hearing Officer, Bay State provided notice of this adjudication by newspaper publication.

On December 20, 1983, NEFI, an incorporated association of independent retail and wholesale home heating oil dealers and distributors in six New England States, filed a Petition to Intervene.

NEFI's Petition triggered a time-consuming dispute with Bay State concerning the legitimacy of NEFI's intervention. On February 17, 1984, the Hearing Officer granted NEFI "full intervenor status" as to aspects of the proceeding involving the marketing of natural gas. See Procedural Order dated February 17, 1984.

Thereafter, Bay State and NEFI contested three particular procedural matters. First, Bay State continued to advance its argument that NEFI's intervention should be dismissed. Secondly, Bay State requested confidential treatment in the form of a Protective Order for certain responses to information requests of the Siting Council Staff. Third, on June 11, 1984 Bay State requested issuance of a subpoena to NEFI directing NEFI to produce, *inter alia*, certain information concerning its members, NEFI's position with regard to the importation of Canadian natural gas, and any information in NEFI's possession on the relative prices of oil and gas throughout the forecast period in Bay State's service territory. Bay State requested the Hearing Officer by subpoena to direct Mr. Charles Burkhardt of NEFI to appear to answer questions on these issues. Bay State filed an additional request for issuance of another subpoena on June 20, 1984, seeking further information concerning NEFI's members.

Both Bay State and NEFI filed several pleadings concerning these issues. As required on Bay State's request, the Hearing Officer issued the requested subpoenas on June 15 and 22, 1984. NEFI filed a Petition to Revoke the Subpoenas on June 29, 1984, and Bay State filed its Opposition to Revocation on July 11, 1984. On August 8, 1984, the Hearing Officer orally stayed for an indefinite period the schedule which had previously been set for NEFI's response to the subpoenas.

On June 15, 1984, the Hearing Officer issued a Protective Order specifying those portions of the responses to the Council Staff's information requests entitled to confidential status. The effectiveness of the Order was stayed, however, pending receipt of NEFI's responses to the subpoenas. The Protective Order specifically provided Bay State with the time required to seek review of the Protective Order as deemed necessary by Bay State. The Hearing Officer's oral issuance of a stay as to the subpoena schedule also served to stay the effectiveness of the Protective Order. The "issues" surrounding the subpoenas and Protective Order remained unresolved until April 11, 1985.

The April 11, 1985, Procedural Order also granted the Late-Filed Petition to Intervene of Distrigas of Massachusetts Corporation ("DOMAC").

B. Background

Bay State serves approximately 193,000 customers in 56 Massachusetts communities. The Company serves three geographic areas surrounding the cities of Brockton, Springfield and Lawrence. Bay State is the third largest seller of gas at retail in the state, ranking behind the Boston and Commonwealth Gas Companies. Actual 1982/83 firm sales totaled 26,438 MMcf, representing approximately 18 percent of the total firm gas sales in Massachusetts.

The Company's service territory is primarily residential. In 1982/83, residential customers represented approximately 93 percent of the total number of customers and accounted for 63 percent of total firm sales. Commercial businesses made up 7 percent of the firm customer base and accounted for 26 percent of total sales. Industrial businesses comprised only 0.4 percent of firm customers and accounted for 10.6 percent of firm sales. Sales are highly temperature sensitive - approximately 63 percent of the 1982/83 normalized firm sales were due to heating load.[1]

Bay State also supplies gas at wholesale to 9 of the 13 remaining utilities in Massachusetts and to 8 utilities in neighboring states. In 1982/83 firm sales to off-system customers were 9 percent of total gas sendout. In addition to selling gas on a firm basis, the Company sells gas to a number of customers on an interruptible basis. These sales amounted to 20 percent of total gas sendout in 1982/83.

Table 1 summarizes 1982/83 sales statistics and service territory characteristics.

Bay State currently has two active subsidiaries, Northern Utilities, Inc. and Bay State Exploration, Inc. Northern has a wholly-owned subsidiary, Granite State Gas Transmission Inc. ("Granite State"), an interstate gas transmission and supply company. Granite

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1. Estimated from Forecast, Technical Supplement.

Table 1
Bay State Gas Company
1982/83 Sales Statistics
(MMcf)

Division

Customer Class	Brockton Customers	Brockton Sendout	Lawrence Customers	Lawrence Sendout	Springfield Customers	Springfield Sendout	Total Customers	Total Sendout
Residential								
With Heating	55,107	6,822	23,378	3,056	44,252	5,528	122,737	15,406
Without Heating	22,567	522	8,809	202	25,193	622	56,569	1,346
Commercial	5,616	2,958	2,239	1,219	5,341	2,657	13,196	6,834
Industrial	392	1,069	128	687	254	1,096	774	2,852
Total On-System Firm(1)	83,682	11,371	34,554	5,164	75,040	9,903	193,276	26,438
Off-System Firm(2)								2,797
Interruptible								8,351
Total Sales								37,586

(1) Excludes company use and unaccounted-for gas.
(2) Off-system sales statistics are not available by division.

State is the sole purchaser of pipeline natural gas supplies from Tennessee Gas Pipeline Company on behalf of Bay State.

C. Previous Proceeding

In its decision on Bay State's Second Long-Range Forecast, the Siting Council approved Bay State's sendout forecast and supply plan subject to numerous conditions concerning methodology, reporting requirements, and supply sufficiency, 9 DOMSC 129 (1983). In that proceeding, the Council reviewed the Company's gas sendout forecasting methodology in great depth.[2] Similarly, the Council examined the Company's ability to meet the peak day requirements of its on- and off-system customers. For the first time, the Council examined Bay State's ability to meet the requirements in each of its divisions, along with its ability to meet system-wide requirements.

Bay State prepared its 1981 forecast of sendout requirements using the ordinary least squares regression technique. Actual monthly sendout data was regressed on degree day data. The resulting intercept term was assumed to be a proxy for daily base load (sendout at a zero degree-day level), while the slope of the regression line was used as an estimate of heating use per degree day. These use factors were taken as representative of the system-wide daily base and heating use factors of existing customers under normal year, design year and peak day weather conditions.

The Company projected that both the base and heating use factors would grow 3 percent per year. The Company stated gross load additions were restricted to about 6 percent per year, but that due to conservation and load loss, net growth was expected to be approximately 3 percent per year. The Company projected that each of its divisions would grow at the same annual rate of 3 percent.

Using these base and heating use factors, and the appropriate weather criteria, the Company projected future sendout requirements under normal year, design year and peak day weather conditions. The Company allocated the forecasted normal sendout to the residential sector on the basis of several undocumented assumptions regarding customer use factors. The remaining normal year requirements were

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2. Siting Council Regulations require that a company's forecast be based on substantially accurate and complete historical data and on reasonable statistical projection methods. In past proceedings, the Siting Council has found projection methods to be reasonable if they are appropriate (technically suited to the size, nature, and resources of the utility), reviewable (such that another person given the same information and expertise could duplicate the results), and reliable (such that the methodology, data and judgements inspire confidence that the forecast predicts what is most likely to occur). Fitchburg Gas & Elec. Light Co., 10 DOMSC 181 (1984).

allocated to the commercial and industrial sectors in a subjective manner which the Council found to be unreviewable, 9 DOMSC at 153-54.

The Council noted the seriousness of its concerns over Bay State's use of a single equation to estimate the behavior of its entire customer base, over an entire year. The methodology, particularly the assumption that both base use and heating factors would increase 3 percent per year in all divisions, did not account for the temperature responsiveness of existing load, the temperature-sensitive nature of potential new load additions, or for the variations in load growth potential across the Company's service territory. The Company did not document how it planned to meet its load growth goal, or whether it was in fact attainable. No consideration was given to the potential types of load to be added (base or heating load or end-use types) nor how the added load would impact seasonal and peak requirements. Conservation assumptions were neither documented nor reflected in customer use factors, 9 DOMSC at 158.

The Council found the Company's forecasting methodology seriously deficient in terms of sophistication, documentation and more importantly, reliability. Many assumptions underlying the forecast of sendout were not provided. Subjective judgement provided the basis for a large part of the forecast, rendering it unreviewable. Consequently, the Council found little basis on which to judge the accuracy or reliability of the forecast, 9 DOMSC at 165-66.

Bay State was directed to make substantial improvements to its forecast methodology and documentation, 9 DOMSC at 205-06. Specifically, the Company was ordered:

- to meet with the Council staff to discuss the development of an adequate forecasting framework to address specific concerns outlined in the Order (Condition 5);
- to provide all data and judgements used to estimate historical and projected customer use factors in each class and to document how these data were incorporated into the forecast of sendout requirements (Condition 4);
- to address the impact of conservation on sendout requirements (Condition 2);
- to report on its procedure to monitor growth potential in its service territory (Condition 3);
- to discuss the issue of gas decontrol and its effect on total forecasted sendout (Condition 1); and
- to report certain sales and forecast data on a disaggregated basis (Condition 7).

On the supply side Bay State was ordered to address several issues, 9 DOMSC at 105-06. These included:

- its ability to meet sendout requirements during a prolonged period of cold weather (Condition 9);
- its ability to meet sendout requirements in the event of design weather in the 1984/85 split-year (Condition 8);

- its process for evaluating the costs and benefits of incremental gas supply surpluses (Conditions 10); and
- the treatment of off-system gas sales in Council tables (Condition 6).

Bay State has satisfactorily met only a few of these conditions, has partially complied with others, and failed to address the condition requiring a cold snap analysis for each division.

Bay State has satisfactorily complied with those conditions requiring changes in the Company's reporting of certain sales and forecast data. The Company has submitted disaggregated historical and forecasted sales data for each of its three service territories (Condition 7). Additionally, the Company has identified its firm and optional off-system sales as well as contracts which guarantee delivery through a pipeline interconnection, and therefore impact peak day requirements (Condition 6). The Company demonstrated that in the event of a 1984/85 design split-year it would experience no shortfalls on a seasonal basis (Condition 8). Finally, Company representatives and Council Staff met on several occasions to discuss compliance with conditions of the Order (Condition 5).

The Company has partially complied with other conditions. Condition 4 required that the Company provide all data and judgements used to estimate historical and forecasted base use, heating use, and average use factors in each customer class and describe how these data and judgements were incorporated into the forecast. While the Company has outlined in its filing all historical base and heating use factors for all classes, it has not done so for forecasted data. In this regard we find the Company has not met the requirements of this condition. We address these issues in more detail, infra.

The Company has addressed the issue of conservation in greater detail, as required by Condition 2. But the Company has failed to accurately and reliably integrate that effort into its forecast of future sendout requirements. Accordingly, portions of the requirements of that condition are reimposed as Condition No. 4.

Condition No. 3 required the Company to discuss its procedure to monitor growth potential in its service territory, including its policy with respect to the addition of new load and the use of fuel use profiles in the residential sector. In imposing this requirement, the Council was attempting to follow up on a condition imposed on the Bay State in Docket No. 80-13 which directed the Company to conduct a study of customer use.

In response to that earlier condition, the Company responded that because it already had in place a procedure to continually monitor short- and long-term growth potential there were no plans to undertake additional studies. The Council ordered the company to further document these procedures to monitor growth potential.

Again, the Company has attempted to respond to the concerns of the Council in its response. Again, that response is inadequate. The Council orders the Company to address these concerns again in Conditions 1, 2, and 3.

The Council finds that the Company has not addressed its ability to meet cold snap conditions in each of its divisions as required by Condition 9 and we reinstate that requirement as a condition to the approval of this filing. This issue is discussed more thoroughly, infra.

II. Analysis of the Sendout Forecast

In this year's filing Bay State has partially responded to the Council's concerns in the previous Order. However, the Council remains concerned over the reviewability, appropriateness and reliability of Bay State's filing. The Company has submitted monthly division-specific historical data, which form the basis for the forecast of future usage by existing customers. It has provided disaggregated historical and forecast data for each division. And it has discussed, in a very limited fashion, market considerations in the various classes of service. Finally, the Company has made some changes in components of its forecast, most notably the normalization process.

Nonetheless, documentation remains incomplete and in the case of normal year, design year and peak day forecast methodologies, is non-existent. Certain methodological issues are unresolved and remain troublesome. The Company has again failed to outline, in any detail, the basis for its forecasted load additions. It has not demonstrated that it understands the temperature-responsive character of its existing and new load additions, and the impact these will have on seasonal, peak and design requirements. Simplistic assumptions form the basis for the allocation of forecasted loads to seasons. Peak day and design year methodologies still do not adequately and reliably reflect the potential impact of planned load additions on sendout requirements.

The Council believes that if a company is to be able to plan for the long- and short-run resources and facilities necessary to meet requirements in a reliable, economic manner, that a company must be able to predict the usage of existing and new customers under normal year, design year and peak-day weather conditions.

In predicting the requirements of existing customers a company must estimate how usage varies with temperature over the course of the year and how total use and usage patterns are changing due to changes in the various factors which influence gas consumption, including the price of gas, regional economic conditions, and behavioral changes in the stock and characteristics of gas-using equipment (due both to replacements and additions of equipment and improvements in appliance efficiencies).

In predicting future load additions, a company must estimate the types and numbers of customers added (residential, commercial, industrial) and the types and characteristics of end-uses added. Understanding these issues is important because it enables a company to predict the short- and long-run annual, seasonal and peak requirements of its customers. It also gives a company information as to the degree and manner in which it is able to influence total usage and timing of usage, so it may make more cost-effective supply and facility planning decisions in the long-run, and better, least-cost dispatching decisions in the short-run.

Bay State's sendout forecast does not instill sufficient confidence for the Council to even attempt to determine that the Company can plan to meet its customers' needs in an adequate, least-cost fashion.

This decision will focus on discussing the incremental changes in Bay State's forecasting effort since its last filing and the major continuing weaknesses of the current Bay State forecast.

A. Results of the Forecast

System-wide annual on-system requirements in a normal year are forecast to increase 1.5 percent per year between 1982/83 and 1987/88, one-half the annual rate forecast in the previous year.[3] Growth is projected to occur primarily in the Brockton and Springfield divisions, with estimated annual growth rates of 2.0 percent and 1.8 percent, respectively. The Lawrence division is forecast to experience minimal growth, at 0.25 percent per year.

Consumption in the commercial sector is projected to increase the fastest, at 3.3 percent annually. Sales to the industrial sector are projected to grow approximately 1 percent per year. Overall, residential sales are projected to grow 0.8 percent per year. Sales to residential customers with gas heating are projected to grow at an annual rate of 1.4 percent per year, while sales to residential customers without gas heating are projected to decline over 7 percent per year.

Because of their differing growth rates, the various class shares of total sales change over the forecast period. Commercial sales' share increases slightly, from 24 percent of total sendout to 27 percent. The residential sector's relative share is projected to decrease slightly, from 64 percent to 61 percent of total sales. The industrial sector's share is projected to decrease by less than one-third of one percent, to 10.3 percent of total sales in 1987/88.

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3. These figures exclude the impact on growth rates of the requirements of Bay State's wholesale, off-system customers. Off-system annual and on-peak requirements are discussed infra.

B. Analysis of the Forecast Methodology

The following sections discuss the Company's method for addressing each component and the Council's evaluation of the Company's approach.

Section 1 examines the normalization process used to develop a base for projecting future requirements of existing customers. Section 2 examines the Company's projections of additions of new load and customers in each class and year. Section 3 examines the Company's study of residential conservation. Section 4 analyzes how the Company integrates these three components into an overall forecast of sendout requirements in the heating and non-heating seasons of a normal year. Sections 5 and 6 examine the Company's design year and peak day methodologies and the resulting forecasts.

1. Normalization of 1982/83 Sales Data.

In order to develop a base from which to project future sendout requirements of existing customers the Company weather-normalizes its 1982/83 monthly sales data.[4] It does so for each division and for each of six customer groups - the heating and non-heating segments of the residential, commercial and industrial classes. The Company develops an estimate of monthly base use for each customer group by averaging total sales in months in which sendout was judged to be primarily base load.[5] The Company does not adjust these use factors for the changes in the number of meters from one month to the next or for the differences in the number of days in each month.[6]

Any remaining sales in each month are assumed to be entirely heating load. The Company divides this heating load by the number of actual billing degree days[7] experienced in each month to derive a

4. Sales data reflect the volume of gas for which the Company bills in a month, while sendout data reflect the physical volume of gas actually sent out in a month. The difference is captured in the unaccounted-for category.
5. For example, in the residential heating class in Brockton the average of July and August sendout is assumed to be base use in each month of the 1982/83 split-year. However, the months used to estimate base load vary across divisions and subclasses. The basis for selection of these months is unclear and should be explained by the Company in its next filing should it continue to use this method.
6. The variation in the number of meters from one month to the next, and the range in number of meters within the split-year, is quite significant in some cases, and could have a considerable impact on normalized sendout.
7. Billing degree days represent the average of the calendar month degree days for any one month and those for the prior month. The use of billing month degree days is an attempt to more accurately correct Mcf sales in a month with the corresponding number of degree days, since the billing periods do not correspond to a calendar month.

monthly heating factor (heating use per degree day) for each month. Based on annual averages, the Company derives estimates of monthly base use per customer and heating use per degree day per customer.

Using these monthly heating factors (usage per degree day) the Company corrects actual sendout experienced in 1982/83 to account for variations in weather from a normal year weather criteria. This results in weather-normalized estimates of 1982/83 monthly sales for each of the six service classifications, in each of the three divisions. In these adjustments, the Company treats non-heating customers in the same manner as heating customers, correlating an estimated heating use with actual degree days, and correcting this heating load for variations in weather from normal.

Currently, the Company disaggregates sales data on the basis of whether or not a customer uses gas for heating purposes. However, the basis for disaggregation is unclear (i.e., whether it is based on rate classification, and if so, which rates are included under each category).

Formerly, Bay State did not explicitly normalize sales to commercial and industrial customers. The Company stated that because these sales were not predominately temperature sensitive, it was unnecessary to do so.[8] In contrast, the Company currently normalizes not only commercial and industrial heating sales, but also commercial and industrial non-heating sales. The magnitude of the weather adjustment to commercial and industrial sales is large.[9] As a result, the Council must question the Company's undocumented decision to change such a basic assumption regarding the characteristics of a large part of its customer base.

Normalized heating use factors for the commercial and industrial non-heating classes exhibit some unexpected patterns. In the Brockton division, the highest heating use per degree day in 1982/83 occurred in September and October, the third and fourth warmest months of the year, respectively. In the Lawrence division, the industrial group exhibited

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8. Implicit in the Company's regression analysis of aggregate sales was the normalization of commercial and industrial sales. However, in allocating normalized sales to customer classes, commercial and industrial normalized sales were assumed to be equivalent to actual commercial and industrial sales, respectively. The implied adjustment to commercial and industrial heating use may have resulted in an improper allocation to the residential sector.
9. The positive weather adjustment to 1982/83 commercial and industrial sales is equivalent to 30 percent of the total new load added over the forecast period, or 120 percent of the average annual load added over the forecast period.

its highest heating increment in September, at a level two and one-half times the level for January. Heating use for September and October in the Springfield commercial class is negative, indicating that usage in these months is less than the estimated monthly base use, estimated from July and August sales.

These irregularities are counterintuitive and unexplained by the Company. The Council believes they are indicative of underlying problems in the level of aggregation chosen by the Company. The Company has not demonstrated that the groupings exhibit enough similarity in their end-uses and consumption patterns to warrant relying upon them for purposes of normalization. The groupings do not account for different types of commercial and industrial customers or buildings, different intensities of energy usage, or different end-uses, aside from space heating. The attempt to correlate non-heating usage with degree days implicitly assumes that all end-uses are predominately temperature sensitive and positively correlated with weather.

The importance of an accurate and reliable method of normalizing historical sales data should not be understated. An improperly normalized historical data base, used as a baseline for future projections, could introduce more error into a forecast of future gas requirements than an unreliable forecast of new load additions.

An alternate method of disaggregating commercial and industrial sales data which might prove to be more reliable than the Company's current approach is one based on SIC codes. This could eliminate problems created by too much aggregation, and, to some degree, account for consumption differences associated with building types, energy intensity, and temperature sensitivity. Additionally, using SIC-coded data provides an opportunity to analyze changes in the composition of the commercial and industrial base over time, changes in energy use patterns within particular SIC codes, and the responses of certain SIC-code groups to market conditions and marketing policies.

Clearly, such data are already useful to the Company for preparing marketing plans and strategies. The Company has assigned four-digit SIC codes to all of its commercial and industrial accounts for purposes of developing marketing strategies.[10] Approximately 64 percent of commercial and industrial sales are made to customers in ten, two-digit SIC codes.[11]

Accordingly, the Company is ordered to present an analysis of commercial and industrial usage patterns by SIC code, at least at the two-digit level. The appropriate level of disaggregation will have to be determined by the Company after an analysis of existing data. This study of usage patterns should include an analysis of the homogeneity of

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10. Response to Information Requests SF-11, dated May 4, 1984.
11. Estimated from figure provided in Response to Information Request SF-11, dated May 4, 1984.

energy intensity, end-uses, and usage patterns within individual SIC codes. Condition No. 1 addresses this issue.

In future filings, the Company should outline clearly the basis and rationale for its disaggregation of sales data for the purposes of weather normalization. The Company should demonstrate that the manner in which it disaggregates the data is the most appropriate given the characteristics of the customer base and the available information.

Bay State's normalized 1982/83 sales data constitute a major component of the forecast of future sendout requirements. The data represent what the Company expects existing customers sendout requirements will be in future years under normal weather conditions, if all other conditions of 1982/83 remained unchanged, including the number of customers, gas prices, the price of other fuels, other economic factors, the stock and efficiency of energy-using equipment, and the behavioral characteristics of customers.

To forecast what these existing customers will use in future years, it is necessary to project the impacts on energy use of forecasted changes in each of these factors. Similarly, it is necessary to project conservation effects due to behavioral changes and changes in equipment efficiencies, and permanent and temporary losses of customers due to general economic conditions or to lower alternate fuel prices. The Company's treatment of these influencing factors is discussed in the following sections.

2. Forecast of Future Load Additions.

In its previous filing Bay State projected that system-wide load would grow at an annual rate of 3 percent, a figure consistent with the then existing supply and distribution capability.[12] The Company allocated load growth to the residential sector on the assumption that these customers' use factors would remain unchanged from the previous year. Any remaining load to be added was allocated to the commercial and industrial classes in a subjective manner consistent with historical data and Company expectations.[13]

The Council found several problems with the Company's methodology. In particular, the Company's assumption that base- and temperature-sensitive loads would increase 3-percent per year failed to account for the impact that new load additions, if different in energy use characteristics from the existing load, might have on seasonal and peak requirements.

In this year's filing Bay State has modified its method of forecasting future load additions. Still, the Council finds that Bay State has inadequately documented its judgements concerning the factors

12. 9 DOMSC at 143 (1983).
13. 9 DOMSC at 139-140 (1983).

likely to impact load growth plans and projections. While the filing contains a limited, general discussion of market considerations and expectations in each sector, it fails to outline basic information on load added by end-use or by market sector (new construction, conversions, etc.). In the commercial and industrial sectors no distinction is made between gross load additions and expected load loss; only net increases in sales are outlined. No distinction is made between load growth due to the addition of new customers and that due to increased sales to existing customers. Trends in load growth exhibited in prior forecasts are no longer evident in this year's filing, yet the forecast provides no explanation of why these reversals of trends are expected to occur.

a. Residential Sales

The following sections discuss Bay State's forecast of residential load additions. The discussion is divided into several components. First, the Council discusses the information presented in the Company's filing and in response to information requests (Section i). Secondly, the Council presents its analysis of the presented information and outlines the problems identified (Section ii). Finally, we discuss Bay State's marketing and sales data which are part of this record but conflict with the Company's Siting Council Filing.

The Council realizes that the following discussion is very detailed - perhaps to the point of being inappropriate for a decision of this nature. However, this is intentional and necessary so that the Company thoroughly understands the problems associated with this portion of its Siting Council filing.

i) Siting Council Filing

In its filing, Bay State outlines the elementary assumptions which presumably form the basis of the forecast of future load additions in the residential class. The key assumption is that the Company expects to add load to the residential heating class during the forecast period at the same rate as load was added during calendar year 1982.

The Company expects to focus its marketing efforts primarily on three areas: existing non-gas residences which would require minimal service extensions due to their close proximity to gas mains; inactive services; and existing gas residences which do not use gas for heating purposes. The Company states that it will focus equipment sales and rental activity on high efficiency heating units, conversion burners, room heaters and water heaters.[14] Additionally, regarding residential

14. In the filing the Company outlines assumptions regarding annual usage of the various equipment types as follows: high efficiency heating unit - 110 Mcf; conventional heating unit - 128 Mcf; and conversion burner - 125 Mcf.

non-heating customers, the Company states that there will be no additions and that any load losses will be due to heating conversions, based on historical information.

In response to Staff information requests the Company stated that it expected to add 465 MMcf of residential heating load annually, based on "existing sales personnel" and the "areas to be served".[15] This added load is due either to existing customers who add appliances, or customers who convert to gas heating, although the Company cannot provide a breakdown between the two. The Company states that the average annual consumption of a heating customer in all divisions was assumed to be between 110 and 125 Mcf.[16]

Within the tables contained in the filing, Bay State outlines the load it expects to add in the residential sector in each year of the forecast period. In the residential heating sector Bay State projects that it will add a total of 1159 MMcf over the forecast period, or 232 MMcf per year. For the Brockton, Lawrence, and Springfield divisions the annual load addition is projected to be 101 MMcf, 8 MMcf, and 124 MMcf, respectively. These figures are net of conservation.[17] The Company projects that it will lose a total of 420 MMcf in the residential non-heating class over the forecast period, or approximately 84 MMcf per year.

The Company also cites per-capita income, person-per-household, and service-territory gas saturation statistics, as well as population data for New England, Massachusetts and the Company's service territory. The Company states that in the next five years its greatest competitor will be fuel oil, with increasing competition from electric central heating and water heating.[18] However, Bay State gives no explanation of how these various factors will affect its ability to market gas in the the residential sector in the next five years nor does it explain how these factors are accounted for in the forecast.

ii) Analysis of Forecast Data - Residential Heating

An examination of the annual customer and load additions to the residential heating class reveals several inconsistencies in the Company's calculation of new customer additions; end-use assumptions; average annual usage assumptions for new and existing customers; and conservation assumptions.

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15. Response to Information Requests SF-5, dated May 4, 1984.
16. It is unclear whether these estimates are for total consumption or for heating use only. Response to Information Requests SF-16, dated May 4, 1984.
17. The Company's assumptions regarding conservation are discussed more thoroughly <u>infra</u>.
18. Forecast, page unnumbered.

The Company calculates the number of new customers to be added by dividing the net load to be added by the average annual usage of existing customers.[19] This implies that new customers will have the same annual gas requirements as existing customers. However, the Company states that part of its sales effort will focus on marketing high-efficiency burners. Presumably, the appeal of this equipment is that it offers customers the opportunity to substantially reduce gas usage, and therefore total costs. Yet, the Company's forecast methodology treats the average usage of new customers in a manner inconsistent with marketing assumptions. Also, the Company has stated that the average annual consumption for new customers would be between 110 Mcf and 125 Mcf, presumably based on engineering end-use estimates. The method used in calculating the total number of new customers does not support this statement.

Additionally, the Company's method implies that it does not intend to market total gross load added to new customers. In other words, Bay State allocates only net volumes of gas (gross load minus conserved volumes) for marketing to new customers. What becomes of conserved volumes is unclear. Whether these volumes are marketed to existing residential customers, to some other class, or not at all, is not reported by the Company in its filing.

Bay State's filing indicates that it expects residential heating customers to conserve. Yet the Company projects that average annual usage of all customers will not decline over the forecast period. If the Company is forecasting conservation, then customer use factors - base and heating use per degree day - should reflect this.

Additionally, the Company states that it expects existing customers to add new appliances. Although it is difficult to discern from the data in the filing, these appear to be heating customers who are adding room heaters and base load appliances.[20] However, the types of appliances, volumes added and timing of these additions by existing customers is unknown, as is the answer to the question of whether the addition of appliances by existing heating customers will offset conservation in whole or in part.

For there to be no change in the average usage figures from year to year, conservation by existing customers, additions of appliances by

19. Response to Information Requests SF-16 dated May 4, 1984.
20. An analysis of data for the residential non-heating class indicates that for every customer lost from this class, 24.1 Mcf, the overall average annual usage, is also lost, indicating no change in usage by existing customers. Therefore, we infer that all appliances added are in the heating class.

existing customers, and new heating load additions would have to offset one another exactly. Without additional supporting information, we find this to be improbable. In any case, the Company has not shown - even qualitatively, much less empirically - that this is what it is in fact projecting.

The Council finds Bay State's treatment of new load and customer additions in the residential heating class inconsistent and unreliable. This does not mean that the Council challenges the ability of the Company to achieve its projected growth; the Council simply can make no finding on the reliability and attainability of those goals based on the Company's filing. And, regardless of the reliability of the Company's estimates of annual load additions, the Company's treatment of them for forecasting purposes, is neither reviewable nor reliable.

Accordingly, the Council finds that the Company has not adequately demonstrated to the Council that it understands the effect of its load growth plans and projected conservation on total annual requirements and total number of customers to be added. The problem appears to be primarily one of insufficient documentation and care in preparing the forecast.

A well documented forecast of new load additions would outline, among other things, the following:

- the total net and gross load to be added in the residential heating class; and a statement of what the company plans to do with conserved volumes of gas (e.g., market them within the residential heating class or some other class, or not at all);

- the portion of load growth (net or gross, depending on what becomes of conserved volumes) to be marketed to new gas heating customers; the portion to be marketed to existing heating customers who add appliances; and the portion to be marketed to non-heating customers who convert to gas service;

- how equipment end-use estimates are used in projecting the annual requirements of new customers and in determining the number of new customers the company expects to add; and

- how existing customers' annual average usage (base and heat) are expected to change (due to appliance additions, replacements and improving efficiencies); how the average annual usage for new customers differs from existing customers (due to smaller homes, more efficient appliances).

Condition 2 addresses these issues.

iii) Analysis of Forecast Data - Residential Non-Heating

There are also inconsistencies and problems in the Company's forecast of residential non-heating sendout.

As noted previously, the Company states in its filing that all losses in the non-heating class would be due to conversions to gas heating. Yet, careful examination of the incremental changes in the number of residential heating and non-heating customers indicates that over the course of the forecast period the number of customers lost from the non-heating class far exceeds the number of customers added in the heating class (by approximately 75 percent). This contradicts the Company's stated assumption that all customers lost from the non-heating classification would be converted to the heating class. In fact, more residential customers are apparently projected to leave the system than are projected to be added, resulting in a net decrease in the number of residential customers.

In its filing Bay State states that it projects future activity in the residential non-heating class on the basis of historical information. Yet, historically the reverse has been true - the number of new heating customers (both new hook-ups and conversions) has far exceeded the number of customers transferred or lost from the non-heating class by a factor of 1.6.[21]

In its previous filing Bay State projected that the number of residential heating customers added would exceed the number of non-heating customers lost by a factor of 1.5, indicating that all non-heating customers lost from that class were converted to heating service.[22] This old projection is in line with the Company's current assumption that all non-heating customers lost would be due to conversion to gas heat.

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21. Between 1978/78 and 1982/83 the Company added 19,279 customers to the residential heating class. In those same years 12,039 customers were lost from the non-heating class, and are assumed to have been converted to heating service. It is not possible to determine solely from the filed tables the true number of non-heating customers who have converted to gas heating service. In fact, new non-heating customers may be added to the system and non-heating customers may terminate service entirely. The tables reflect only the net change in the number of customers.
22. In its 1981 filing the Company projected it would add 32,804 heating customers and lose 21,641 non-heating customers over the forecast period. See Docket No. 81-13, Tables G1 and G2.

When questioned on the inconsistencies within the current filing and between annual filings, Bay State responded that its filing should be amended to read "...any load lost from the non-heating class will be due to conversion to a heating customer or to alternate fuel."[23]

Still, the Council is unable to resolve these discrepancies. The Company has provided no information to support its amended statements regarding customer losses from the non-heating class. Nor has it outlined the extent to which non-heating customers are terminating gas service for an alternate fuel, or the alternate fuel(s) to which these customers are switching, or the reasons for any trends. Accordingly, we cannot make a determination as to the reliability of these projections.

iv) Marketing Data

In discovery Bay State was asked for the historical information it used for its residential load growth projections.[24] Bay State's response (hereinafter "SF-3") included:

- a two-page narrative which discussed 1983 residential marketing considerations;
- a forecast of 1983 unit and load additions by division (Exhibit A);
- a list of 12 major assumptions behind the 1983 forecast (Exhibit B);
- the 1983 unit and load forecast by month and division (Exhibit C,D,E and F);
- a schedule of 1983 sales promotions (Exhibit H);
- unit and gas line costs projections (Exhibit J);
- the "New Load Summary", a document which outlined for each division, monthly and year-to-date 1981 and 1982 historical load added data in the residential, commercial and industrial sectors;[25] and

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23. Response to Information Requests SF-4, dated May 4, 1984.
24. Specifically, Council Staff requested the Company to provide the historical data for the twelve-month period ending December 31, 1982 which indicated by division and class, the number of customers and load added including the composition of that load (e.g., new-hook-ups, conversions from non-heating). See Information Request SF-3 and Response dated May 4, 1984.
25. Included in this document was an estimate of the split between heating and base load in the residential and commercial classes. In the case of industrial, the split between base, heating, and process load was provided. Also included were monthly and annual load forecasts in each month and division, disaggregated by residential, and combined commercial and industrial. In the Procedural Order dated April 11, 1985, several responses to information requests were afforded protected status. The responses are discussed in only general terms in this Decision to preserve that treatment.

- four pages outlining 1984 unit and load projections by month and division;
- a summary of 1983 new load and unit additions[26]

Bay State's response included neither an explanation of the information contained therein nor any explanation of how this information related to its forecast of future sendout requirements as filed with the Council.

Also, during the course of discovery, the Company submitted its most recent annual sales plan, dated March 1983.[27] This contained a residential services marketing plan outlining the issues expected to influence the Company's ability to market gas to domestic users over the next five years, including demographics, gas prices, deregulation, gas supply and conservation, among other things. Attached as an exhibit to the sales plan were projections of residential sales volumes for the 1983-1987 time period.

The sales plan also outlined a number of key assumptions behind the new load forecast, including an estimate of 1983 housing starts captured by gas, projections regarding conversion activity, estimates of near-the-main prospects, and water heater addition and replacement rates.

The existence, thoroughness and detail of these sales and marketing documents raise serious questions about the soundness of the forecast filings and forecasting process the Company presents to the Council. Most notably, within that single response, presumably offered in support and clarification of the filing, were five different forecasts of what the Company expects its new residential load additions to be in future years.[28]

However, the forecast and historical data contained within SF-3 conflict with the Company's filing, and do nothing to support the Company's Petition before the Council. Similarly, the residential forecast contained in the sales plan differs substantially from that provided in the Siting Council Forecast. Although in one year the sales plan corresponds to the Siting Council forecast, no other information is consistent.

The document SF-3 points to discrepancies between the information the Company uses for internal planning and that provided to the Council. The 1983 and 1984 forecasts (SF-3) contain projections for each month of

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26. It is unclear to what units, or class(es) this information pertains.
27. Response to Information Request D-7 dated May 4, 1984.
28. Within the document SF-3 there are 1983 and 1984 unit and load forecasts; 1982 unit and load historical data, which presumably form the basis for the load projections in the Siting Council forecast; and the unit and load figures contained in the New Load Summary.

the number of units of each end-use (design burners, conversion burners, water heaters and room heaters), the number of new all-gas homes, the number of new gas customers[29] and the number of main and service extensions. Additionally, the New Load Summary outlines for 1981 and 1982 the number of base and heating units actually added and the base and heating load added, presumably based on an engineering estimate of the annual consumption of particular unit types.

Yet, in discovery responses the Company indicated it had no knowledge of the make-up of its load growth goal of 465 MMcf per year. It indicated it did not know the number of new hookups or conversions, nor the split between base and heating load. Clearly, as SF-3 and the Sales Plan indicate, the Company has information regarding how it intends to meet its aggregate load-growth goal. It has information which allows it to estimate historical and forecasted annual base and heating load additions by end-use, as well as the number of new hook-ups and conversions in each year.

This information should be an integral part of the Company's filing with the Council. Any petition which contains less than such basic information as projected load additions by end-use and base and heating load, and new hook-ups and conversions, is wholly inadequate.

The Council cannot begin to reconcile the various conflicting information provided by the Company. Any attempt to do so would require protracted rounds of discovery or hearings, or both. To truly uncover the Company's growth plans or what it can reasonably expect to occur in its the residential markets, would require the Siting Council Staff itself to reproduce the Company's forecasting process and forecast. Given the already protracted nature of this proceeding, the Council believes that such a process would not be beneficial. The resources of the Company and Staff would be better spent working to improve future forecast submissions.

It is apparent to the Council that Bay State, either consciously, or otherwise, has established two planning frameworks - an internal one used for budgeting and marketing purposes and a second one, designed to fulfill Siting Council requirements in a minimum way. It is unclear whether Bay State's failure to integrate the two frameworks into a single process which meets the requirements of both, results from an unwillingness to do so, or an inability to transform that internal plan into a format that complies with Siting Council rules and regulations.

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29. It is unclear from the document whether this is the number of new gas heating customers (including new homes, conversions of inactive or non-gas service and conversions of non-heating services) or new gas customers (which would include new hook-ups and reactivated services, only).

Regardless of its motivation, the Company is on notice that in future filings it will be expected to present a Forecast Petition which is consistent with its own internal documents, both in content and in the level of documentation. A company of Bay State's size and resources must be more responsive to the Council's requirements. It must demonstrate to the Council that it thoroughly understands its markets, and, as such, is able to reliably project future requirements.

These issues are addressed in Condition No. 2.

b. Commercial and Industrial

The Company states that its commercial and industrial sales efforts will seek to add new customers while assisting existing customers in their energy usage decisions. The Company will use its rates, policies, advertising, and sales force to accomplish these two main objectives.

The Company states in its filing that "[a]fter research and considerable discussion, the Commercial Industrial Sales Department concluded that the incremental gas load due to new business customers would represent about 1 MMcf per year from 1983/1987."[30] The Company also states that "..each year the Company's sales managers review the year's sales record to date and, tempered (primarily) by forecasted business conditions and energy prices, establish a sales "goal" for the coming year."[31] The filing further states that, at the time, "[t]he goal for 1984 has not yet been formulated, but will likely be between .8 MMcf and 1 MMcf."[32]

However, an examination of the tables in the filing indicates that, on average, the Company projects that it will add 283 MMcf of load annually. This figure is the net change in commercial and industrial sales each year; there is no indication of the gross amount of load added or lost each year. Furthermore, the tables indicate that Bay State expects to add, on average, 450 new commercial and industrial customers in each year of the forecast period. Again, the figure represents the net change and gives no indication of the number of customers lost in each year due to business closings.

In attempting to rectify the two figures reported in the filing (the 0.8-to-1 MMcf per year sales goal, and the 283 MMcf reported in the tables) one could conclude that the 1-MMcf projected increase in sales is attributable to <u>new</u> commercial and industrial customers, as stated, while the 282 MMcf difference between 283 MMcf and 1 MMcf, is attributable to increased sales to <u>existing</u> customers.

However, closer examination of the forecast data raises doubt regarding this possible explanation. Comparing the number of <u>new</u>

30. Forecast, Section II, page unnumbered.
31. <u>Id</u>.
32. <u>Id</u>.

commercial and industrial customers added and the 1 MMcf increase in sales presumably due to new customers, reveals that on average a new commercial or industrial customer is projected to use slightly over 2 Mcf per year. This seems highly improbable given that the average domestic water heater consumes approximately 30 Mcf per year and the 1982/83 average annual use per Bay State account for existing commercial customers is approximately 540 Mcf and for industrial customers, approximately 3,800 Mcf per year.

The Company was asked in discovery to rectify these inconsistencies: the estimate of sales attributable to new business customers (1 MMcf per year between 1983-1987), the yet-to-be-established 1984 sales goal (between 0.8 and 1 MMcf), and the annual average net increase in commercial and industrial load as reported in the filed tables (283 MMcf per year). The Company responded that "[t]he incremental gas load attributed to new business customers is anticipated to be about 1 MMcf per year. However, there will be switching to alternate fuel, conservation, and cutbacks due to economic conditions. The net increase has been shown in the forecast."[33] Clearly, this response does little to clarify that information already available to the Council.

In its filing, Bay State references its five year (1983-87) marketing plan. This document, provided in discovery, outlines those market sectors and business types which, due to their energy use and fuel selection characteristics, the Company expects to target.[34] Also included in this document were detailed discussions of those factors likely to influence Bay State's ability to market gas in the commercial and industrial sectors in the coming five years: available equipment and changes in equipment technology; cogeneration; the availability of dual-fuel equipment; demographics; conservation; marketing programs and policies; and gas and oil prices. As an addendum to the sales plan, Bay State presents electric, oil and gas price forecasts through 1990, and 1983 and 1984 commercial and industrial sales forecasts by general end-use (space heating, base, and process).

Those annual forecasts provided with the five year marketing plan do not agree with the Siting Council forecast for the same years and do little to support the Company's filed forecast. The Council cannot reconcile the conflicting information and accordingly cannot make a finding on the reliability of the Forecast before it.

One final piece of evidence submitted by Bay State is the Stone and Webster commercial sector marketing study - a detailed analysis of the commercial market in Bay State's service territory, as well as an analysis of the potential for new sales.[35] It discusses future

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33. Response to Information Requests SF-7 dated May 4, 1984.
34. Response to Document Request D-7 dated May 4, 1984.
35. The Stone and Webster Commercial Market Study, Preliminary Report, August 1982 was supplied in response to Document Request D-9 dated May 4, 1984.

expectations regarding gas' marketability; new technologies; fuel selection criteria; and population, personal income and employment growth trends. In addition, the study gives a very detailed analysis by SIC codes of energy use profiles, and current fuel source by end-use. The study also outlines those SIC codes which due to their fuel use characteristics are attractive marketing targets.

Again, problems arise in attempting to establish a link between the material and observations presented in the Stone and Webster Report and information in the Siting Council filing. It is unclear what role, if any, the Stone and Webster Study played in the development of Bay State's commercial and industrial forecast. Judging from the information before the Council, the study played no role in the development of the Forecast.

The information within the Siting Council filing does little to inspire confidence in the Company's added load projections. While the Company's internal sales plan and the commercial market study do nothing to substantiate the Siting Council forecast, they do indicate the type of information available to the Company in formulating marketing plans.

Clearly, Bay State commissioned the Stone & Webster Commercial Market Study in order to aid in marketing strategy formulation. It is unfortunate that Bay State has not taken the information provided to it in order to bridge the gap between its marketing plans and strategies and the forecast it prepares for the Siting Council. These factors examined by Stone and Webster are precisely the ones that a well-prepared forecast should consider. This is true of both the commercial and industrial sectors.

While the Company chooses to omit price data, SIC-code data and end-use information from its Siting Council forecast, it has demonstrated that it examines these same data in its internal planning. This is not acceptable. The Council expects Bay State to use the same tools of analysis in its Siting Council Forecasts as those used in its marketing plans.

Specifically, in its commercial and industrial forecast, Bay State should discuss its expectations regarding the price of gas and the prices of competing fuels, dual fuel users, technological developments, and the makeup of its new commercial and industrial customers by SIC codes at least at the two-digit level.

At a minimum, Bay State should present its commercial and industrial load growth plans on the basis of SIC code. The Company should outline which SIC market groups it intends to target, the reasons for that particular strategy and support for its expected new commercial and industrial load composition.

Additionally, in preparing its commercial and industrial new load forecasts, the Company should outline what end-use types it expects to target during the forecast period and the impact these plans are expected to have on normal and design, annual, seasonal, and peak requirements.

The Company should address these concerns in its response to Condition No. 3.

3. Conservation

In response to Condition 3 of the Council's previous order, the Company conducted a study of residential conservation. Using multiple regression analysis, the Company quantified the annual reduction in usage per degree day per customer from April 1978 to March 1983. The Company assumed average use per meter per month is a function of degree days, degree days squared and four additional (dummy) variables which measure the change in usage per degree day from one split-year to the next.

The result of the Company's study indicates a fairly consistent decline in use per degree day per customer in the heating class.[36] The estimated annual average historical reduction in usage per degree day are 3.7 percent for Brockton, 6.0 percent for Springfield, and 4.6 percent for Lawrence.[37] The estimated annual change in total annual requirements are 2.3 percent 3.3 percent, and 2.5 percent, respectively.

In order to project future reductions in annual requirements the Company regressed the decline in annual requirements over time. The projected conservation rates in the residential class are 1.6 percent for Brockton, 1.2 percent for Springfield, and 1.7 percent for Lawrence.

In studying historical conservation the Company did not distinguish between conservation during the non-heating season, conservation during the heating season and conservation on peak.[38] Other companies have observed that conservation rates are greater during summer and shoulder months than during the heating season and peak periods.[39] Accordingly, it is possible that Bay State's conservation rates based on annual averages overstate the conservation which can realistically be expected to occur during the heating season and other peak periods.

Given the closer margin of supplies over requirements that exists during the heating season and peak periods as compared to other times of the year, it is important that a company have a sense of the variability of conservation across the year. The Siting Council believes that Bay State should develop seasonal conservation estimates for those classes for which it is projecting conservation. Accordingly, the Council

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36. The residential non-heating group in the Lawrence division did show some fluctuation in use per degree day, however the Company attributes this to changes in customer mix with respect to builder classification.
37. These figures were reported incorrectly by the Company in its initial petition. The figures cited above are corrected. See Response to Information Request SF-12 dated May 4, 1984.
38. Response to Information Request SF-15 dated May 4, 1984.
39. See Boston Gas Company 1984 Long-Range Forecast Supplement, Docket No. 84-25, and 10 DOMSC 278 (1984).

requests the Company, in its reexamination of conservation in its next filing, to give attention to the issue of seasonal conservation rates. Additionally, the Company should state its expectations regarding conservation on peak and illustrate how it reflects this in its forecast of future requirements.[40] Condition No. 4 addresses this issue.

The Council makes several additional observations regarding Bay State's conservation study.

Most prominent is the Company's own observation that "...the projections implicitly assume that the conditions which define them remain unchanged"[41] and that "[the] model was designed to measure conservation to date, not to forecast demand. As such, it intentionally excludes variables such as price, disposable income and other determinants of demand."[42] In line with the Company's own observations, the Council cautions the Company in its use of the conservation estimates in projecting future conservation.

Secondly, the Council notes discrepancies between the historical and forecasted conservation rates reported in the conservation study and those calculated from the average use figures reported in the Forecast tables.[43] Historical average heating use figures show a decline of nearly 12 percent between 1978/79 and 1979/80. But, between the 1979/80 and 1981/82 split-years heating use per degree day remained stable, for a total average annual decline of slightly over 3 percent per year. In those same years base use decreased over 5 percent per year.[44] Total average usage per customer (base and heating) declined by slightly less than 3 percent over those same five years.

In short, the data in the filing indicate historical trends different from what is reported in the Company's conservation study. Specifically, the Company's annual data presented in the filing show no decline in heating usage with all conservation being manifest in the base usage.

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40. Currently the peak day forecast implicitly assumes conservation by residential heating customers. This is because peak requirements are assumed to grow at the same rate as normal year and normal year sales have a dampened growth rate due to the effects of conservation.
41. Forecast, Exhibit 2, page unnumbered
42. <u>Id.</u>
43. Reported on those tables are heating use per degree day and annual base use per customer. Although the Council has nothing on the record regarding how these figures were derived, based on its understanding of the previous forecast methodology, it is assumed that these usage figures were derived using regression analysis.
44. Between 1978/79 base use per customer also increased by over 3 percent. Between 1979/80 and 1981/82 base use per customer declined by 7.9 percent per year, for an average annual decline of over 5 percent for the five years.

Thirdly, we note that the Company assumes that no conservation will occur in the commercial and industrial sectors. Without elaborating, the Council notes, the Company's marketing plan totally refutes this assumption. As noted, in the commercial and industrial sectors the Company makes no distintion between gross and net load additions, and in fact some of the load erosion projected in this class could be conservation. The Company should state its expectations regarding commercial and industrial conservation in future filings. It should distinguish between load loss due to business closings and load loss due to conservation.

Finally, the Company projects conservation in the residential heating class ranging from 1.2 percent to 1.7 percent per year - yet fails to reflect the conservation in its forecasted customer use factors.[45] The projected average annual use per customer figures show minimal or no decline over the forecasted period. For these to be consistent with the forecast conservation figures, new customers would have to use significantly more gas, on an annual basis, than existing customers. Yet, the Company calculates new customers by assuming they have the same annual requirements as existing customers.

As the Council has stated numerous times, "[t]he ability to forecast sendout accurately depends upon forecasting conservation"[46] and "[i]f the Company is projecting conservation by existing customers.. the customer use factors should reflect this."[47] In this regard, we find that the Company has not adequately complied with the requirements of Condition 3 of the previous order. While the Company has made a commendable effort to measure historical conservation, it has failed to adequately integrate that information into its overall forecast of sendout requirements. As discussed previously, the Company has not reflected the forecasted conservation in the projected number of new customers. Accordingly, the Company is ordered to reflect any forecasted conservation both in forecasted customer use factors and forecasted customer additions. Condition No. 4 also addresses this concern.

In sum, while the conservation study is an admirable attempt to rigorously quantify conservation to date and project future conservation, the Company's application of its results is inexact by comparison. In fact, in terms of sophistication, the bulk of the Bay State forecast by comparison is seriously lacking. The Council would like to see the Company distribute its forecasting resources in a more even manner, improving the whole of its forecast efforts together. In this way the key elements of the forecast - normalization, new load

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45. Assuming that consumption patterns, as reflected in usage figures, will remain unchanged, the Company reports constant annual average use factors in each division in both the residential heating and non-heating classes. Forecast, Tables G-1 and G-2.
46. See <u>In Re Boston Gas Co., et al.</u>, 4 DOMSC 50, 64 (1980).
47. See 9 DOMSC 129, 158 (1982).

forecast conservation estimates, and documentation - would be more balanced in terms of sophistication, appropriateness and reliability.

4. Normal Year Forecast

Bay State's filing contains no documentation regarding the development of the forecast of normal year requirements. To the extent possible, Council staff gained its knowledge about Bay State's forecast only after analyzing thoroughly the numbers contained in the filing. The normal year forecast is the cornerstone of any company's filing and the level of documentation presented in Bay State's filing is inadequate. Ironically, previous Company filings contained more information regarding normal year methodology than the present filing. The Council expects a company to progress - not regress - in its forecasting efforts over the years.

In future filings the Company must state explicitly how it incorporates its projections of future load additions into the forecast of normal year sendout requirements. The Company must state its expectations regarding the temperature sensitivity of new load additions and the distribution of new load across the year, at least at a seasonal level. It must document its projections and assumptions, and illustrate its calculations with examples. Condition 5 addresses this issue. If the Company feels it is unable to comply with the requirements of this condition, it should seek assistance from Council staff.

In forecasting normal year future sendout requirements, Bay State proceeds in the following way. The Company normalizes 1982/83 historical sendout by division and class. These seasonal figures become the base for the forecast of future sendout requirements, for both normal and design year planning purposes.

Next, the Company adjusts the residential heating gross load addition figures for expected conservation (although, as discussed above, it is not clear that the Company has properly reflected conservation in this class). The Company assumes no conservation in the residential non-heating, commercial or industrial classes. Conservation rates are assumed to be the same in the non-heating and heating seasons.

In allocating new load additions across the split-year the Company makes the simplifying assumption that new load will be distributed between seasons in the same proportion as 1982/83 existing load. For an example, if historically 34 percent of residential heating sales occurred in the non-heating season and 64 percent occurred in the heating season, Bay State assumes that net new load added will be distributed in the same proportion. This holds true for all customer classes.[48]

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48. However, because the different classes are growing at different rates annually, the seasonal composition of total load is forecasted to change slightly over the forecast period, with heating season sendout becoming a greater proportion of total sendout by the end of the forecast period.

The Council believes to be highly improbable the assumption that new load will exhibit the same distribution across seasons as existing load. In future filings the Company should explicitly support its assumption regarding the allocation of new load across seasons and state its expectations regarding the type and temperature sensitivity of new load, the timing of new customer additions, and the types, temperature sensitivity and timing of load losses.

Additionally, the Council suggests the Company consider using monthly data as a more appropriate and reliable way to incorporate its annual new load projections into the normal year forecast.[49] To the normalized monthly data, the Company could add monthly estimates of new load additions. Annual estimates of new heating load could be allocated to months on the basis of the normal monthly degree day distribution. In the case of commercial and industrial loads, where load types may not be so clearly defined, judgements regarding the targeted market sectors use patterns might have to replace more rigorous methods. This is an area where SIC coding could be potentially valuable.

Alternately, the Company could make more realistic assumptions regarding the base/heating composition of new load and its distribution across the year using its knowledge of load types to be added.[50]

5. Design Year Forecast

All gas companies plan their resources and facility requirements on the basis of a design weather criteria, the worst seasonal conditions for which a company plans to meet firm requirements. Bay State bases its design year planning on the assumption that the worst conditions it will experience in a split-year will be such that the total split-year will be 10 percent colder than a normal split-year. Furthermore, all additional degree days in a design year are assumed to occur in the heating season, so that a design heating season is nearly 13 percent colder than a normal heating season.

Bay State forecasts that system-wide design sendout requirements will be 6.8 percent greater than normal year sendout requirements. This relationship is projected to hold true for each year of the forecast period. Because all additional degree days in a design year are assumed to occur in the heating season in each year, design heating season sendout requirements are approximately 10 percent greater than normal heating season requirements.[51] Design requirements are forecast to grow

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49. See Commonwealth Gas Company First Supplement to the Second Long-Range Forecast, 1983, Docket No. 83-5.
50. See Boston Gas Company Second Supplement to the Second Long-Range Forecast, 1984, Docket No. 84-25.
51. These figures exclude the impacts of the increased requirements of off-system customers during a design year. The Company assumes that wholesale customers will request all optional winter volumes during design weather conditions. Off-system requirements are discussed in detail <u>infra</u>.

at the same annual rate as normal requirements throughout the forecast period. As discussed next, this appears to be so because they are forecasted as a percentage of normal requirements.

Further examination of the Company's filing shows that the relationship between design and normal heating season sendout in each division differs from that of the system as a whole. In the Brockton, Lawrence and Springfield divisions, design heating season sendout exceeds normal heating season sendout by 10.4, 10.8 and 9.5 percent, respectively.

An analysis of the Company's 1982/83 sendout data shows that the relationship between design heating season sendout and normal heating season sendout for that particular year is approximately the same relationship as that forecast in the current filing for each of the divisions.[52] Had a design year occurred in 1982/83 in the Brockton, Lawrence and Springfield divisions, requirements would have been 10.1, 10.2 and 9.5 percent greater than normal, respectively. Although, these "historical" relationships are not exactly those forecast, they are sufficiently close that, absent any other documentation, one could conclude that the Company developed the forecast relationship based on the 1982/83 figures. With no other information before it, the Council can only conjecture as to this conclusion.[53]

As was true of the normal year forecast, the Company provided no documentation of design year forecast methodology in its filing. Given the lack of documentation in support of the design methodology we have nothing on which to judge its appropriateness or reliability. The Council staff, however, makes several observations regarding the contents of the filing.

In general, in each division and each forecast year, design and heating season sendout are proportional by the same factor. Yet, if one examines the types of load expected to be added and lost by the Company this assumption loses its credibility. For example, in the Lawrence division in 1984/85, 82 percent of total load projected to be added is to be added in the heating season; 90 percent is due to heating customers; and 64 percent to heating customers in the heating season. Arguably, this pattern of load additions would have the effect of aggravating design and peaking problems. The Council has seen evidence in other cases that heating use per degree day is greater in the heating

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52. Using the reported monthly design degree day data (See Table DD, page unnumbered) staff calculated expected design heating season sendout for each division for 1982/83. These figures approximate the volume of gas that customers on the system would have used in the 1982/83 split-year had design weather conditions occurred.
53. Alternately, the Company may have used regression analysis in developing the historical relationships between normal and design heating season sendout and in forecasting design heating season sendout.

season than in the non-heating season, and that heating use per degree day is most likely greater during the design year than during a normal year, given the same customer composition, 9 DOMSC at 16-19. It is not clear that the Company captures this phenomenon in its design year forecast and is an issue which should be addressed in future filings.

Because of the importance of the design year forecast to a company's commitment to new resources and/or facilities, it should be among the most carefully prepared elements of a company's forecast. As well, it should be among the most thoroughly documented elements of a company's forecast.

That Bay State's failure to provide any documentation on its design year forecast methodology is not acceptable. In its next forecast, the Company shall present a detailed description of its design year forecast methodology, including, but not limited to, a description of all historical and forecast data used, including heating and base use factors, and a discussion of how new load additions are expected to effect design requirements.[54] Conditions 6 addresses this issue.

6. Peak Day Methodology

A peak day is the coldest day for which a company plans to meet the sendout requirements of its firm customers. In the case of Bay State, firm customers include those off-system customers guaranteed delivery on a peak day. Next to the design year methodology, the peak day methodology is perhaps the most important aspect of a company's sendout forecast. A company determines the adequacy of its existing facilities, capacities and daily supply sources in part from its peak day requirements.

Once again, Bay State provides no explanation of the method it uses to forecast peak day sendout requirements during the forecast period. The only related information provided in the filing is contained in the technical supplement. Based on 1982/83 historical data the Company computed a daily base load and a heating increment, presumably applicable to a January peak day.

In discovery, the Company was asked to explain the basis for its peak day forecast figures, for each division and year. Additionally, the Company was asked to outline those volumes of gas guaranteed to off-system customers on-peak, and assumptions made regarding new customers' contribution towards peak day sendout.[55]

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54. If new load is expected to be increasingly temperature sensitive, as the current filing indicates, it might be expected that design requirements are exacerbated by the addition of temperature sensitive loads. It is this issue, among others, which we expect Bay State to address in its next filing.
55. Response to Information Request SF-19 dated May 4, 1984.

In response, the Company provided, for each division and year, the daily base-use and heating-use-per-degree-day figures which formed the basis for the peak day calculations. Additionally the Company outlined those off-system customers guaranteed delivery on-peak and the volumes guaranteed. However, Bay State failed to outline the method by which it developed the usage factors.

Again, Council staff was required to infer the actual methodology used and assumptions made by the Company in forecasting peak day divisional requirements. Apparently, that the Company assumes peak day base load (calculated from the January base-use estimate divided by 31) and heating use per degree day will grow at the same annual rate as total firm sendout requirements.[56]

Again, the Company's methodology fails to account for the temperature sensitivity of new load additions. If the Company's new load additions are predominantly temperature sensitive - and the forecast and sales data indicate they are - then peak day requirements are likely to grow at a faster rate than total annual requirements. Just as heating season requirements are projected to grow at a faster pace than non-heating season requirements (8.0 percent versus 6.9 percent, respectively), peak day requirements are likely to grow at a faster pace than total split-year or heating season sendout requirements.

For a Company that is responsible for meeting nearly 20 percent of the peak day requirements in the Commonwealth, this method is neither appropriate nor reliable. Accordingly, the Company is ordered in its next filing to develop and document a methodology which addresses the changing nature of its customer base, including the temperature sensitivity of new load additions. Further, the Company should specifically state its assumptions regarding peak day use factors. Condition No. 7 addresses this concern.

7. Off-System Sales

Bay State is unique in that a major portion of its sales are to other gas utilities for resale to end users. The Company currently has 9 off-system customers in Massachusetts and 8 in surrounding states. At the time of the filing, volumes under contract for the 1985/86 split year totalled 4,163 MMcf. Of this amount, 3,010 MMcf was firm while 1,153 MMcf was at the purchaser's option. Over 70 percent of these volumes are under contract for the heating season.

The Council realizes that some of these contracts have been renegotiated since the Company filed. However, the Council has not

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56. This is essentially the same assumption made by the Company in its prior forecast, where it was assumed that since the goal was to have firm on-system requirements increase 3 percent annually, then peak requirements would grow accordingly.

attempted to modify Bay State's forecast of off-system sendout. The Council expects Bay State to update this information in its next filing. The Company is also expected to continue to provide that level of information on off-system sales and contracts as provided in this year's filing. Condition 8 addresses this issue.

The Council is also aware that all of the Company's off-system contracts expire in March 1988. Although the expiration of these contracts is not an issue in this review (because the relevant date falls outside the time-frame of the Supplement) the next filing should address the issue. With the availability of numerous new supply sources, many of Bay States off-system customers may opt to reduce significantly, or opt out of completely, their LNG contracts. To the extent that Bay State is not able to market this gas to interruptible customers or use it to displace higher cost gas in its own dispatch, Bay State's retail customers may be adversely effected. In sum, with Canadian and domestic gas available in the near future to many of its off-system customers, Bay State may find itself with considerable gas surpluses in the 1988/89 split-year and beyond.

8. Summary

In previous Decisions and Orders concerning Bay State's forecast, the Council has attempted to give the Company guidance as to improvement of its forecast methodology and documentation. The Company has been conditioned to better document its forecast and the data and judgements which comprise it. It has been ordered to present a study of customer use factors and to further document and describe its procedures to monitor growth potential. Yet, it has repeatedly failed to adequately respond to the Council's orders and requests.

To some extent, the Company's failure to comply with these requests has been the failing of the Council to fully articulate its requirements. However, the Council believes that its regulations outline in sufficient detail what its mandate requires of gas companies. It should not need to reiterate them with every company and every Decision and Order.

In this decision, and for the reasons identified at the onset, however, the Council has attempted once again to remedy this situation. We have outlined in detail those requirements upon which the approval of this filing is conditioned.

The Company <u>shall</u> address the <u>specific items</u> outlined within the text of this decision - not only the more general issues outlined in the Conditions at its conclusion.

Accordingly, Council Staff shall be available to the Company to provide assistance with meeting the requirements of this Order.

III. Resources and Facilities

In the past, the Council has focused its supply side reviews primarily on a gas company's ability to meet the requirements of its firm customers. In the past, the Council has not scrutinized the costs of gas supply alternatives, but examined mainly the adequacy of a company's resources to meet normal year, design year and peak requirements.

However, with the range of supply alternatives currently available or awaiting approval, at different prices, deliverability levels, and contract terms, the Council is compelled to examine whether a gas company's choice of supplies is consistent with the Council's mandate to ensure "a necessary energy supply with a minimum impact on the environment at the lowest possible cost." Mass. Gen. Laws Ann. ch. 164, sec. 69H (emphasis added).

We have previously stated, "[in] the future, the Council will attempt to review each company's basis for selecting a supply alternative or the company's decisionmaking process to ensure that the company's decision are based on projections founded on accurate historical information and projection methods."[57]

In reviewing Bay State's current filing, the Council has examined, as before, the adequacy of Bay State's supplies to meet its firm customers' normal year, design year, and peak day, and cold snap requirements. However, as stated, the Council is unable to make a finding on the reliability of Bay State's forecast of sendout requirements under all conditions, and therefore can make no determination regarding the reliability and cost implications of the Company's supply planning.

With the above caveat and assuming the Company's requirements are as projected, it appears that in the short-run, with existing supplies, the Company is able to meet the requirements of its customers under the worst conditions of design weather and significant forecast error.[58]

Although satisfied that the Company will not experience a supply shortfall in the short run, we are not so satisfied in the long-run. Similarly, the Council is unable to determine whether the Company's plan ensures a necessary supply at the lowest possible cost. We are in no way suggesting a deficiency in the Company's supply planning. Rather, the Council is providing notice of the intended scope of future proceedings. In spite of our reservations regarding the reliability of

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57. Fall River Gas Company, Docket No. 84-20, 12 DOMSC__ , (1985).
58. If 1985/86 design heating season requirements are 5 percent greater than forecast, the Company would be able to meet firm sendout requirements. However, this assumes that propane is available as previously under contract.

the Company's sendout projections, we present in the following sections an analysis of what the Company presents in its filing.

A. Resources

Bay State receives the majority of its pipeline natural gas from two major suppliers under four contracts. The Granite State Gas Transmission Company provides pipeline natural gas to the Bay State under its CD-6 rate schedule.[59] Algonquin Gas Transmission Company provides pipeline natural gas to the Company under two contracts. The bulk of this supply is provided year-round under the F-1 rate schedule. Firm winter service is provided under Algonquin's WS-1 rate schedule. Additionally, the Company has contracts with Algonquin for synthetic natural gas (SNG), purchased during the heating season. However, as discussed <u>infra</u>, the Company has chosen to market out of this supply source for the remainder of the contract period, which ends September 31, 1987.

To supplement its pipeline supplies, the Company has a contract with DOMAC for the purchase of imported LNG. Proposed contract amendments are for the purchase and transport of propane. These are discussed <u>infra</u>. Additionally, the Company has three contracts for the purchase and transport of propane. These are discussed within.

The Company has agreements with both of its pipeline suppliers for underground storage service. The agreements provide for the storage by Bay State of pipeline gas during the non-heating season and best-efforts redelivery to Bay State during the heating season. Except as noted below, these contracts are unchanged from the previous year, and will not be discussed in detail.

The Company's Brockton division is served only by Algonquin. The Lawrence and Springfield divisions are served by Tennessee. As such, certain supply sources are allocated to divisions based on this constraint, in addition to contractual constraints on volumes which the Company is allowed to take at each city-gate station. Table 2 summarizes the provisions of the Company's existing supply contracts.

1. Proposed CD-6 Contract Amendments.

Tennessee has filed a certificate application with the Federal Energy Regulatory Commission ("FERC") to revise its delivery obligations on a daily and annual basis for various customers, including Granite State.[60] Additionally, Tennessee has requested authorization to

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59. On April 1, 1982 Bay State's and Granite State's contract with Tennessee Gas Pipeline Company merged into a single contract between Granite State and Tennessee. As a result of this merging, the natural gas is now provided by Granite State to Bay State. Forecast, page unnumbered.
60. Tennessee Gas Pipeline Company, FERC Docket No. CP84-441-000.

Table 2
Bay State Gas Company
Existing Supply Sources

I. PIPELINE SUPPLIES

Supplier	Contract	AVL/ACQ (MMcf)	MDQ (MMcf)	Contract Expiration Date
Granite State	CD-6	20,950	65.8	11/1/2000
Algonquin	F-1	9,027	33.4	11/1/89
Algonquin	WS-1	1,092	18.2	11/16/89
Algonquin	SNG-1	2,766 (1)	18.1	9/30/87

II. STORAGE AGREEMENTS

Supplier	Contract	Storage Capacity (MMcf)	Maximum Daily Withdrawel (MMcf)	Contract Expiration Date
A. Underground Storage				
Granite State	GSS	1623	14.8	4/1/2000
Granite State	Penn York	1894	17.2	3/31/95
Algonquin	STB	677	7.5	4/15/2000
Algonquin	SIS	800	8.0	6/5/86

III. SUPPLEMENTAL

	Contract Quantities (MMcf)	Contract Expiration Date
A. LNG (4)		
		1/1/2000
DOMAC	2610	
Proposed Amended ACQ	3110	
B. PROPANE		
Petrolane Northeast	550 (Firm)	3/31/85
Gas Service	367 (Optional)	
C.M. Dining	26 (Firm)	3/31/85
	17 (Optional)	
Country Gas	28 (Firm)	3/31/85
Distributors	18 (Optional)	

(1) The Company has elected its option to completely market out of this supply source for the remainder of the contract period.
(2) The transportation of all underground storage gas is currently on a best-efforts basis.
(3) One of load of propane is equivalent to approximately 9000 gallons or 826 Mcf.

transport storage return gas on a firm basis for certain of its customers, discussed infra.

Tennessee's application proposes to increase Granite State's maximum daily quantity ("MDQ") and annual volumetric limitation ("AVL") by approximately 43 MMcf and 10,700 MMcf, respectively. The record before the Council does not indicate what portion of these increases will be passed on to Bay State. Accordingly, Bay State is directed to discuss in its next filing on the status of this FERC proceedings, and its participation in this proposal, by way of any precedent agreements or contracts executed or anticipated to be executed with Granite State.

2. F-1 Contract Amendments/Proposed F-4 Rate Schedule

In its recent FERC rate case,[61] Algonquin proposed to increase the annual contract volumes for its customers from the current 270 times the F-1 MDQ to 280 times the MDQ. The proposal was approved for a one-year test period beginning with 1983-84 split year. At the time of its filing, Bay State expected that the proposal would be extended beyond the one-year test period. However, since the time of Bay State's petition, Algonquin has restructured its proposal.

Algonquin now proposes to sell additional gas volumes under the proposed new F-4 rate schedule.[62] Interim interruptible service is proposed to begin immediately upon authorization by FERC. During this period it is proposed that Bay State receive a maximum of 5,112 Mcf per day. Beginning on November 1, 1985 a developmental period will begin under which Bay State will receive 2,442 Mcf per day and 891,330 Mcf annually on a firm basis. Finally, beginning on November 1, 1986, full service will begin. During this phase Bay State will receive 5,112 Mcf per day and 1,865,880 MMcf annually.

3. SNG-1 Tariff Revisions

In November 1984, FERC accepted a revised SNG-1 rate schedule. The revisions have incorporated expanded flexibility into the tariff provisions allowing Algonquin's customers to respond to gas supply need under changing operating conditions. Bay State has opted to take advantage of this new flexibility by completely marketing out of future SNG-1 deliveries, while retaining, within certain parameters, the right to call on this supply. The schedule provides that a customer may request supplemental one-year quantities before the start of each heating season and spot deliveries during the SNG season. The availability of such supplemental and spot quantities is dependent upon Algonquin's ability to obtain the necessary feedstock supply. The Council commends the Company for marketing out of its highest cost supply, in light of the availability of other lower cost alternatives.

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61. Algonquin Gas Transmission Co., FERC Docket No. RP83-44.
62. Algonquin Gas Transmission Co., FERC Docket No. CP84-654-001

Currently, Tennessee is authorized to transport 21,818 Mcf per day on a best-efforts basis for Granite State. Of this amount, Bay State is entitled to 17,222 Mcf per day. Tennessee is proposing to continue best-efforts transportation for Granite State's account at a reduced volume of 6,818 Mcf per day and 749,980 Mcf per year. The remainder of this daily entitlement, 15,000 Mcf, would be provided on a firm basis. All of this gas would be transported to the Bay State's Lawrence division.

As is the case with the proposed amendments to Tennessee's CD-6 contract, it is unclear what portion of the benefits of this project, namely the transportation upgrades, would flow to Bay State, and which would flow to Bay State's subsidiary, Northern Utilities. The Council requests that the Company clarify this matter in its next filing.

Also, the record indicates that Granite State's request for upgrade of the Consolidated transportation remains unsatisfied. Again, the Company should indicate the status of this request in its next filing.

5. Proposed DOMAC Contract Amendments

Bay State obtains imported LNG from DOMAC under a contract which expires on January 1, 2000. This contract currently provides a maximum annual quantity of 2,610,000 MMBtu. Although DOMAC will vaporize up to 10,000 MMBtu daily for Bay State, transportation from DOMAC to Bay State via Boston Gas and Tennessee is on a best-efforts basis. See Boston Gas Company, 10 DOMSC 278, 322 (1984).

In 1983 Distrigas of Massachusetts Corporation filed an application with FERC to amend its Certificate of Public Convenience and Necessity. The purpose of the amendment was to reflect an agreement entered into by DOMAC and its customers. The agreement results from a contract amendment between Sonatrach, the Algerian national oil company, and DOMAC's affiliate, Distrigas Corporation, to amend the existing LNG contract. The Amendment, among other things, provided for a new pricing mechanism, and modifications in contract quantities and delivery schedules.

The Agreement between DOMAC and its customers provides for changes in the annual contract quantities and truck Call Out Rights for certain of DOMAC's customers. The agreement also provides that the parties shall cooperate in efforts to achieve a connection from DOMAC's terminal to an interstate pipeline to facilitate deliveries by DOMAC to its customers.

The agreement provides that Bay State's annual contract quantity be increased by 500 BBtu annually beginning in April 1984, bringing the Company's total annual entitlement to 3110 BBtu. It provides that should Bay State agree to increase its ACQ by more than 500 BBtu before April 4, 1984, such additional increase shall be utilized to satisfy Boston Gas' request for additional reductions in ACQ.

The SNG-1 contract expires in October 1987. Algonquin has indicated that its "willingness to operate the facility after 1987 will depend on the seasonal volumes and production rates requested by the customers".[63] The Company is requested to discuss in its next filing its plans regarding SNG-1 after the contract expires.

4. Underground Storage Transportation Upgrade

As discussed previously, the Company has four long-term contracts for underground storage services. Underground storage from Granite State is provided through two contracts. The first, with Consolidated Gas Supply Corporation, provides a storage capacity 1,622,660 MMBtu. The second storage service, with Penn-York, provides a storage volume of 1,894,000 MMBtu and a maximum daily delivery rate of 17,200 MMBtu. Currently, all of the gas stored under these two arrangements must be used in the Lawrence and Springfield divisions.

Additionally, the Company has two contracts with Algonquin for underground storage service. The first, under the STB storage schedule, provides a gross storage volume of 676,960 MMBtu with a daily delivery rate of 7,522 MMBtu. The second, under the SIS rate schedule, is a short-term contract with an expiration date of June 15, 1986. The contract provides 800,000 MMBtu of storage capacity and 8,000 MMBtu daily withdrawal quantity.

Currently, the transportation associated with all of these storage contracts is on a best-efforts basis and therefore not considered a reliable gas supply on the coldest days of winter season. However, Granite State has requested that Tennessee upgrade to firm the transportation of both the Consolidated and Penn-York storage services.[64, 65]

As discussed previously, Tennessee has a certificate application proposal pending before FERC in which it is requesting authority to provide firm transportation of storage gas for certain of its customers.[66] Granite State is slated to receive 15,000 Mcf per day of firm transportation in conjunction with the Penn-York storage service.

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63. In Re Algonquin SNG, Inc., No. 84-36, 12 DOMSC __ (1984).
64. It is Granite State, not Bay State, which contracts with Tennessee for all gas supply, storage and transportation services. Likewise Bay State, in turn, contracts with Granite State for similar services.
65. See letter dated February 21, 1984 from R. Orris, Granite State, to A. Baker, Tennessee. Response to Information Request S-2 dated May 4, 1984.
66. Tennessee Gas Pipeline Company, FERC Docket No. CP84-441-000. Tennessee has filed a Proposed Settlement Agreement dated February 5, 1985, covering the transportation of storage gas in Docket No. CP84-441-002.

The agreement provides that Bay State increase its vaporization from 10,000 MMbtu per day to 11,920 MMbtu per day. Additionally, it provides for an increase in truck Call Out Rights from 11.0 trucks per day to 13.1 trucks per day, based on the new ACQ.

Pending action by FERC, all parties apparently are operating under the terms of the proposed amendment.

LNG can be delivered from DOMAC's import terminal at Everett, Massachusetts, to all of Bay State's divisions by transport trailer and can be delivered, during the period November 1, through March 31, to Bay State's Lawrence and Springfield divisions by pipeline displacement utilizing the facilities of Boston Gas Company and Tennessee. However, while the vaporization by DOMAC is firm, transportation by Boston Gas and Tennessee is best-efforts. As such, it is not considered as a pipeline gas supply on the coldest day of the winter season. Normally, all of the LNG which is received from DOMAC during the period April 1 through October 31 is transported to LNG facilities for storage until the following winter season.

6. Propane

At the time of its filing, Bay State had three long-term propane contracts. The largest, with Petrolane-Northeast Gas Service, Inc., provides for an annual volume of propane equivalent to 917,431 MMBtu. The other two contracts with C.M. Dining, Inc., and Country Gas Distributors, Inc., are relatively small. These contracts provided annual volumes equivalent to 43,199 MMBtu and 45,872 MMBtu, respectively. Transportation of all propane volumes under contract are the responsibility of the suppliers. The Company is entitled to a total of 18 truck loads per day. All of these contracts have initial expiration dates of March 31, 1985. However, all provide for unilateral extension by Bay State for five years, or on a year-to-year basis, by the mutual consent of the parties involved.

For purposes of analyzing the adequacy of the Company's supply plan, the Council has assumed that all of these contracts will be in effect throughout the forecast period. In its next filing, however, the Company is requested to submit any new propane contracts and to discuss in detail its planned propane purchases throughout the forecast period.

7. Boundary/CONTEAL/Trans-Niagara

In 1984, FERC approved a Settlement Agreement in Phase 1 of the Boundary Proceedings providing for firm initial service (FIS) of partial Boundary Gas volumes to four companies, including Bay State.[67] On November 1, 1984, Bay State began receiving 9,928 MMBtu per day at its Springfield division.

67. Boundary Gas, Inc., et al., Docket Nos. CP-107-000, et.al.

The FERC proceeding on the Phase 2 Boundary import project is progressing slowly before FERC. The Company's filing indicates that it expects the project to come on-line beginning in November 1986. In the event that the full Boundary project is not approved, the FIS will continue with an initial termination date of October 31, 1992. Otherwise, the FIS project will terminate when full volumes begin flowing.

During proceedings before FERC on the Boundary and Trans-Niagara Canadian Gas Projects, two new sources of supply for the Northeast emerged. Consolidated Gas Supply Corporation and National Fuel Gas Supply Corporation proposed to sell volumes of domestic natural gas to customers in the northeast United States, including Algonquin, for resale to certain distribution companies, including Bay State. This proposal is referred to as the CONTEAL proceeding and constituted Phase 1A of the Boundary Gas Project.

The Phase 1A settlement was approved in June 1984 and service began November 1, 1984. At that time, Bay State began to receive 9,764 MMBtu per day from CONTEAL, delivered to the Brockton Division. On November 1, 1985 the gas will be available on a firm basis. As part of the settlement, Bay State's purchases from CONTEAL will diminish to 6,706 MMBtu per day on November 1, 1986. The initial termination date of the CONTEAL project is October 31, 1992.

Algonquin has agreed to deliver on a best-efforts basis all or a portion of the CONTEAL volumes to Tennessee at the existing interconnection between Tennessee's and Algonquin's pipeline at Menden, Massachusetts. Additionally, Tennessee has agreed to deliver on a best-efforts basis this volume to Bay State's Springfield and Lawrence divisions.

Bay State is also a participant in the proposed Trans-Niagara project pending at FERC. The Company's filing reflects the January 1983 decision of the Canadian National Energy Board to reduce by half all pending gas export applications, including the Pan Alberta-Algonquin contract. Thus, the Company forecasts that it will be entitled to 1,452 BBtu per year and 3,978 MMBtu per day. At the time of its filing the Company expected gas supply from the project to be available beginning in November 1, 1986.

The Council questions whether any of these Canadian projects will provide the projected supplies by the forecasted dates. Since Bay State filed this Supplement, there have been delays to the FERC proceedings due to continued negotiation regarding the price of gas imports, and competing FERC certificate applications regarding pipeline transportation arrangements, and competing sources of supply. Given the pace of these projects, the Council requests Bay State to discuss these projects in depth in its next filing and to adjust the anticipated commencement dates. Bay State should be prepared to justify its decisions regarding levels and terms of purchases as compared to other supply alternatives. Condition 9 addresses these issues.

8. Conservation Programs

The Siting Council evaluates conservation programs as a supply source on the same basis as other supply sources. The Siting Council considers these programs as part of its mandate of ensuring necessary gas supplies at the lowest possible cost with a minimum impact on the environment. Mass. Gen. Laws Ann. ch. 164, sec. 69H. Bay State's Supplement does not discuss conservation in terms of deliberate action being taken by a gas company to meet requirements which otherwise would be met from conventional supply sources (as opposed to "conservation" in the form of observed customer behavior). At a time when Bay State has supply alternatives and must plan for new contracts, the Siting Council believes conservation should receive concurrent attention. The Council also notes that there may be Company-sponsored conservation programs which, in conjunction with other supply resources, could reduce total supply costs below what it costs to supply customers without such conservation.

We recognize that Bay State has an active division, Con-Serve, which promotes energy saving services.[68] Additionally, the Company has contracted with a third-party vendor, Citizens Conservation Corporation, for conservation services in conjunction with the LAFUT funds.[69]

The Siting Council requests the Company to address such programs in its next Supplement, and the potential impact and cost-effectiveness on its supplies.

B. Facilities

Bay State reports no changes to its LNG and propane facilities since its last filing. Table 3 summarizes the capabilities of the Company's existing LNG and propane facilities.

The largest of the Company's LNG facilities is located in Ludlow, in the Springfield division. This facility has storage, liquefaction and vaporization capabilities. The second major LNG facility is located in Easton in the Brockton division. This facility has only storage and vaporization capabilities. Two small LNG satellites are located in the Brockton division. A third satellite is located in Lawrence.

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68. Response to Information Request SF-20 dated May 4, 1984.
69. Response to Document Request D-7 dated May 4, 1984.
70. We note that the Bay State's Prospectus indicates that the Company undertook a "major project to improve vaporization capacity of one of the Company's liquefied natural gas (LNG) storage facilities." Yet, the filing does not reflect this. See Prospectus, June 17, 1983, Response to Information Requests D-4 dated May 4, 1984.

Table 3
Bay State Gas Company
Existing LNG and Propane Facilities

Location	Division	Storage Capacity (MMcf/day)	Vaporization Capacity (MMcf/day)	Liquefaction Capacity (MMcf/day)
LNG				
Ludlow	Springfield	1020	55	7.5
Easton	Brockton	8000	35	-
Marshfield	Brockton	8	12	-
Scituate(1)	Brockton	0	4	-
Ludlow(2)	Brockton	0	4	-
Lawrence	Lawrence	13	19	-
Providence	N/A	100	N/A	-
Propane				
W. Springfield	Springfield	79.3	25	
E. Longmeadow	Springfield	59.5	13	
Northhampton	Springfield	24.5	11	
Brockton	Brockton	79.6	22	
Taunton	Brockton	32.4	12	
W. Medway	Brockton	20.3	5	
Lawrence	Lawrence	24.5	22	

(1) These are portable LNG vaporizers and have no associated storage.

The Company has a contract for 100 MMcf of LNG storage in the Algonquin LNG, Inc. storage facility in Providence, Rhode Island.[71] LNG is delivered to this facility during the non-heating season from both the DOMAC and the Company's Ludlow LNG facility by transport trailer. Redelivery of this LNG to the Company is by transport trailer and/or by pipeline displacement to the Brockton division utilizing the facilities of Algonquin and Providence Gas Company. This delivery is on a best-efforts basis and is not considered as a reliable supply source on the coldest days of winter.

The Company has seven liquid-propane (LP) air plants located throughout its service territory. Three of these LP air plants are located in the Brockton division. The Lawrence division has a single LP air plant while the Springfield division has three facilities. The storage and vaporization capacities of these plants are also outlined in Table 3.

IV. Comparison of Resources to Requirements

A. Normal Year

During a normal year the Company must have sufficient resources to meet the requirements of its firm customers; to refill underground and LNG storage before the start of each heating season; and to meet fuel gas requirements for storage injection, withdrawal, transportation and liquefaction. Bay State must also have sufficient LNG and/or propane supplies on hand to meet the firm and optional requirements of its off-system customers.

Tables 4 and 5 summarize the Company's forecast of heating and non-heating season requirements and the resources it plans to use to meet those requirements.

1. Normal Non-Heating Season

During a normal non-heating season, in addition to the requirements of firm on-system customers, Bay State requires approximately 780 MMcf to meet the needs of its off-system customers.[72] Additionally, the Company requires gas to refill underground and LNG storage.[73]

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71. Although the filing makes no mention of it, other information in the record indicates that the annual LNG storage quantity at the Algonquin facility is scheduled to increase to 118 MMcf in 1987. See Prospectus, June 17, 1983, Response to Information Requests D-4 May 4, 1984.
72. During the non-heating season the Company assumes that off-system customers will request only firm volumes.
73. Not shown in the Company's Tables are the supplies necessary to refill propane storage. The Council expects all inventory activity to be accurately reported in future filings.

Table 4
BAY STATE GAS COMPANY
COMPARISON OF RESOURCES TO REQUIREMENTS
NORMAL NON-HEATING SEASON

	1985/86	1986/87	1987/88
REQUIREMENTS			
Normal Firm Sendout	10192	10327	10462
Sales For Resale	779	779	779
Subtotal	10971	11106	11241
Interruptibles	9430	8943	8869
Fuel Reimbursement			
Storage Refill			
Underground	2058	2146	2146
Propane			
LNG	384	199	555
TOTAL	22843	22394	22811
RESOURCES			
Tennesse CD-6	11310	11310	11310
Interruptible	1000	1000	1000
Boundary	2125	2125	2345
Algonquin F-1	4067	4067	4067
Interruptible - I-1/I-2	350	300	300
Consolidated	400	0	0
CONTEAL	2089	2089	1435
Trans-Niagara			851
DOMAC LNG	1444	1444	1444
Propane	58	58	58
TOTAL	22843	22393	22810

(1) Staff has adjusted the F-1 volumes to reflect the changes in the that project by Algonquin. In the absence of additional information, the Council has assumed that the Company would take its full MDQ each day of the heating season and the remainder of the ACQ in the non-heating season. Interruptible sales have been adjusted accordingly.

Table 5
BAY STATE GAS COMPANY
COMPARISON OF RESOURCES TO REQUIREMENTS
NORMAL HEATING SEASON

REQUIREMENTS		1985/86	1986/87	1987/88
Normal Firm Sendout		20985	21307	21629
Sales For Resale		2231	2252	2798
Subtotal		23216	23559	24427
Fuel Reimbursement		124	99	118
TOTAL		23340	23658	24545

RESOURCES				
Tennesse	CD-6	9640	9640	9640
Storage Return	GSS	733	733	942
	Penn York	736	736	947
Boundary		1499	1655	1655
Algonquin	F-1	4960	4960	4960
	WS-1	1092	1092	1092
Storage Return	STB	419	677	677
	SIS	800	0	0
CONTEAL		1474	1013	1013
Trans-Niagara			601	601
Algonquin LNG		100	100	100
LNG from Storage		99	455	605
DOMAC LNG		1666	1666	1666
Propane		123	331	649
TOTAL		23341	23659	24547

Bay State projects the availability of interruptible pipeline supplies from both Algonquin and Granite State throughout the forecast period. If this gas should not be made available, it would have no effect on the Company's firm on- or off-system customers, but would reduce sales to interruptible customers.

The Company expects to take its full entitlement of LNG from DOMAC in each non-heating season. When these volumes (1444 MMcf) exceed the requirements of LNG storage refill and off-system customers, the difference must be sent out. Assuming the accuracy of the Company's forecast of sendout requirements is reliable, Bay State's supply plan reflects sending out LNG in the 1986/87 and 1987/88 non-heating seasons.

Depending on the outcome of the pending contract amendments, the level of DOMAC LNG volumes sent out in summer could increase. In future filing the Company should outline the impact of increased DOMAC volumes on summer operations. Specifically, the Company should address the changes in system cost and reliability resulting from the proposed contract quantity, scheduling and dispatching amendments.

There may be reasons, other than take-or-pay obligations, for which the Company would need to send out LNG in summer. Specifically, physical constraints, such as an inability to move pipeline gas between divisions, might require use of more costly supplies. The Company should discuss any such reasons in its next filing.

Additionally, LNG storage refill requirements shown on Table 4 are those following a normal heating season. As discussed in the following section, colder than normal weather in the previous winter would increase storage refill requirements in the following non-heating season. In that sense, the additional LNG purchases and liquefaction capabilities might be required in the non-heating season to provide the extra refill requirements, both of Bay State and its off-system customers, which would follow a design heating season.

The Company's filing also indicates that it plans to dispatch a small amount (58 MMcf per year) of propane in the heating season of each year. Presumably, this is the take-or-pay portion of the Company's summer propane allocation. In future filings, however, the Company should so state and provide a summary of its monthly firm and optional quantities of propane under contract.

Should none of the proposed new gas supply projects come on-line as projected, Bay State will still be able to meet the projected normal year non-heating season requirements of its customers. It is not clear how the Company's normal year, non-heating season dispatch would differ should any or all of the new projects come on line.

2. Normal Heating Season

During the heating season of a normal year, Bay State must have available sufficient sources of supply to meet the temperature sensitive requirements of its on- and off-system customers. To meet these requirements, Bay State plans to take its full seasonal allocation of Granite State's CD-6 supplies. Additionally, the Company plans to take from Algonquin its full daily allocations of F-1 and WS-1 volumes for the full heating season.

The Company plans on receiving full heating season deliveries of gas from its SIS storage service through its expiration in 1986, and 62 percent of the STB volumes in 1984/85 and 1985/86. In 1986/87 and 1987/88 the Company plans on receiving full STB volumes. However, the transportation associated with both of these storage contracts are on a best-efforts basis only.

The Council has reservations regarding the ability of the Company to receive full storage volumes during the winter season. In the 1983/84 heating season, a period 67 percent warmer than normal, the Company received only 62 percent of the total volumes requested for the STB and SIS services.[74]

Accordingly, should the Company continue to project the redelivery of 100 percent of volumes stored under these contracts, it should present support for such projections. It should also discuss how it would replace this supply should it not be available as projected.

B. Design Year

1. Design Non-Heating Season

Because the Company assumes that a design non-heating season has the same number of degree days as a normal non-heating season, the requirements of its firm on-system customers are the same under both conditions. However, because LNG storage and propane are used in greater amounts during a design heating season, storage refill requirements in the following non-heating season are greater.

Additionally, Bay State's off-system customers are projected to increase their requirements during a design non-heating season, due to their increased storage refill requirements. These additional volumes are projected at the optional contract volumes. In comparing resources to requirements, the Company outlined all resources which it projected would be available to it, rather than the resources it would use to meet design non-heating season requirements. In future filings the Company shall outline what supplies it plans to dispatch in a design non-heating season. Tables 6 and 7 summarize the Company's design non-heating and heating season requirements and resources.

In the non-heating season the Company shows the availability of over 5000 MMcf of interruptible gas from Tennessee and Algonquin, over four times the amount projected to be available during a normal

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74. Response to Information Requests S-3 dated May 4, 1984.

Table 6
BAY STATE GAS COMPANY
COMPARISON OF RESOURCES TO REQUIREMENTS
DESIGN NON-HEATING SEASON(1)

REQUIREMENTS	1985/86	1986/87	1987/88
Normal Firm Sendout	10192	10327	10462
Sales For Resale	1179	1179	1179
Subtotal	11371	11506	11641
Interruptibles	0	0	0
Fuel Reimbursement			
Storage Refill			
Underground	3366	3089	3614
Propane			
LNG	1764	1764	1764
TOTAL	16501	16359	17019

RESOURCES			
Tennesse CD-6	11310	11310	11310
Interruptible	5000	5000	5000
Boundary	2125	2125	2345
Algonquin F-1	4067	4067	4067
Interruptible - I-1/I-2	750	750	750
Consolidated	400	400	400
CONTEAL	2089	2089	1435
Trans-Niagara			851
DOMAC LNG	1444	1444	1444
Propane	58	58	58
TOTAL	27243	27243	27660

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(1) The Company has not properly reflected in its filing how it would actually dispatch to meet design non-heating season conditions. It has only indicated total volumes available. Whether all remaining gas would be sold to interruptibles in unclear.

Table 7
BAY STATE GAS COMPANY
COMPARISON OF RESOURCES TO REQUIREMENTS
DESIGN HEATING SEASON

REQUIREMENTS		1985/86	1986/87	1987/88
Normal Firm Sendout		23114	23467	23820
Sales For Resale		2984	3011	3739
		26098	26478	27559
Fuel Reimbursement		178	167	194
TOTAL		26276	26645	27753

RESOURCES				
Tennesse	CD-6	9640	9640	9640
Storage Return	GSS	1256	1466	1622
	Penn York	1156	1471	1893
Boundary		1499	1655	1655
Algonquin	F-1	5049	5049	5049
	WS-1	1092	1092	1092
Storage Return	STB	677	677	677
	SIS	800	0	0
CONTEAL		1474	1013	1013
Trans-Niagara			601	601
Algonquin LNG		100	100	100
LNG from Storage		1664	1664	1664
DOMAC LNG		1666	1666	1666
Propane		204	552	1081
TOTAL		26277	26646	27753

non-heating season. The Company has not substantiated why it would expect a greater availability of interruptible supplies following a design heating season. It should state its expectations regarding this in its next filing. Should this gas not be available, it would not effect the ability of the Company to meet firm requirements.

The Company's filing indicates no purchase of CONTEAL volumes during a design non-heating season. We assume this is an error, and have shown CONTEAL purchases on Table 6.

2. Design Heating Season

During a design heating season Bay State must have sufficient resrouces to meet the additional temperature sensitive requirements of its firm on-system customers and the additional requests of its off-system customers. During a design heating season the Company also uses more fuel gas due to increased LNG and propane vaporization. The Company expects to meet these additional requirements by taking increased quantities of storage return gas, and by vaporizing additional quantities of propane and LNG.

In the 1985/86 heating season the Company plans on receiving full volumes of STB and SIS storage return gas. The Council has already expressed its reservations regrading this projection. Should only fifty percent of these volumes be available, the difference could be made up with propane. The Company's propane contracts existing at the time of the filing provided for a total of 938 MMBtu of propane during a heating season (535 MMBtu firm, 403 MMBtu option). Additionally, the Company plans to start the heating season with 320 MMBtu of propane in storage.

In 1986/87 and 1987/88 the Company expects supplies from Trans-Niagara and Phase 2 of the Boundary project. We have already expressed our concerns regarding potential delays in these two projects. Should the full Boundary project not be approved, Boundary FIS volumes will continue. In this case the Company could make up the deficit with increase propane vaporization.

In the event that both the Boundary Phase 2 project and the Trans-Niagara projects fail to receive the necessary approvals as projected, the Company could be short of necessary requirements by 757 MMBtu. Propane or volumes from the F-4 proposal (772 MMBtu), if approved, could make up that dificit.

Additionally, should the F-4 proposal be approved it is possible that certain of Bay State's off-system customers might consider reduction or elimination of their purchases of LNG from Bay State, reducing its requirements. See Fall River Gas Co., Docket No. 84-20, 12 DOMSC __ (1985). Also, the Council would expect that should these new supply sources not be forthcoming, Bay State would modify its marketing plans to reflect the changed circumstances. The Company should address these issues in its response to Condition No. 9.

C. Peak Day

In addition to having sufficient gas supplies to meet the seasonal and annual requirements of its customers, a company must have sufficient daily pipeline supplies and facility capacities to meet the peak day requirements of its customers. A company must be able to meet the requirements of its entire service territory, as well as the requirements of each of its divisions. Table 8 outlines Bay State's system wide peak day resources and projected requirements through the forecast period. These peak day sendout figures include the requirements of off-system customers.[75]

From existing supply sources and facilities Bay State has a system wide peak day capacity of 371 MMBtu, a margin of daily sendout capacity over requirements of 38 percent in 1985/86. Under the settlement agreement discussed supra, on November 1, 1984 Bay State began receiving 9,764 MMBtu per day from the CONTEAL project at its Brockton division and 9,928 MMBtu from the Boundary FIS at its Springfield division.

On November 1, 1986, the daily entitlement from the CONTEAL proposal will diminish to 6,707 MMBTu. At that time, the Company projects that the full Boundary Proposal will provide 10,959 MMBtu per day and that the Trans-Niagara will provide 3,978 MMBtu per day. This will bring the Company's total daily supply to 373 MMcf, providing a 35 percent margin of supplies over requirements in 1987/88.

Should the Boundary and Trans-Niagara projects not be approved within the forecast period, the Company will have sufficient daily capacity from existing sources to meet its projected requirements. In fact, the Company will still maintain a considerable margin of supplies over reserves - projected at 33 percent in 1987/88.

Table 9 summarizes the daily pipeline supplies and facility capacities allocated to each of Bay State's divisions and the projected peak day requirements in each of those divisions. The Brockton division is served only by the Algonquin Pipeline; the Lawrence and Springfield divisions are served by the Tennessee pipeline. All three divisions have propane and LNG vaporization capabilities.

Currently, all volumes from the CONTEAL project are allocated to the Brockton division, while all of the volumes from the Boundary FIS are allocated to the Springfield division. A majority of the volumes from the Full Boundary projects will be allocated to Lawrence. The remainder will be allocated to Springfield. Trans-Niagara volumes, when available, will also be allocated to Brockton.

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75. Bay State indicates that four of its off-system customers are guaranteed delivery through a pipeline interconnection on a peak day. They are: Westfield (1.2 MMcf), Holyoke (4.2 MMcf), North Attleboro (1.4 MMcf), and Middleborough (1.2 MMcf). Response to Information Request SF-19 dated May 4, 1984.

Table 8
Bay State Gas Company
Peak Day Sendout

	Actual 1982/83	1985/86	1986/87	1987/88
Algonquin				
F-1	33	33	33	33
ST-1	10	0	0	0
WS-1	8	18	18	18
SNG-1	14	0	0	0
Tennessee				
CD-1	54	65	65	65
Storage	2	0	0	0
Propane	35	110	110	110
LNG Vaporization	86	125	125	125
CONTEAL		10	7	7
Trans Niagara			4	4
Boundary FIS		10		
Boundary			11	11
Total Resources	242	371	373	373
Forecast Requirements	242	268	273	277
Percent Reserve		38	37	35

Table 9
Bay State Gas Company
Peak Day Sendout
Divisonal Totals

BROCKTON	1985/86	1986/87	1987/88
Algonquin			
F-1	33	33	33
WS-1	18	18	18
Propane	39	39	39
LNG Vaporization	51	51	51
CONTEAL	10	7	7
Trans Niagara		4	4
Total Resources	151	152	152
Forecast Requirements	116	118	121

LAWRENCE	1985/86	1986/87	1987/88
Tennessee			
CD	19	19	19
Propane	21	21	21
LNG Vaporization	19	19	19
Boundary		9	9
Total Resources	59	68	68
Forecast Requirements	52	53	53

Springfield	1985/86	1986/87	1987/88
Tennessee			
CD-1	46	46	46
Propane	50	50	50
LNG Vaporization	55	55	55
Boundary FIS	10		
Boundary		2	2
Total Resources	161	153	153
Forecast Requirements	100	102	103

As the Table indicates should none of these projects receive approval, each of the Company's divisions will have sufficient daily resources to meet projected peak day requirements through the forecast period, even allowing for some error in forecasting requirements.

D. Cold Snap

The Siting Council has defined a cold snap as a period of peak or near-peak weather conditions, similar to the two-to-three week period experienced during the 1980/81 heating season. The Company's ability to meet the requirements of a cold snap depends on its daily pipeline entitlements, its daily supplemental sendout capacity and its storage inventories.

In its previous Decision the Council found that on a system-wide basis Bay State was well situated for managing a cold snap in the upcoming heating season. However the Council noted that in its next filing the Company should explain and demonstrate that it would be able to manage its resources so that it was equally well prepared for a cold snap in future years. As a condition to the approval of its filing the Company was ordered to demonstrate both the availability of resources and sendout capacity to meet such cold snap conditions in each of its divisions.[76]

In response the Company replies: "During the meetings between council staff and representatives of Bay State Gas Company, it was decided that Bay State does have sufficient resources to meet prolonged series of days at or near peak conditions. It has been suggested by staff, therefore, that this issue has been addressed sufficiently at the meetings and does not require additional discussion at this time."[77]

The Council notes that while it encourages cooperation between its Staff and the Company, such an exchange of information does not constitute record evidence satisfying the requirements of an adjudicatory proceeding. A company's ability to meet cold snap requirements is a complicated factual issue. Further, the Council itself is the ultimate fact-finder. Thus, the Council still requires that the Company demonstrate in its filing that it has fully met the requirements of all conditions. In this regard, we find that the Company has not met the requirements of this Condition. As such, it is reimposed as a condition to the approval of this year's filing, and affixed hereto as Condition No. 10.

Staff has conducted an analysis of Bay State's ability to meet cold snap conditions in each of its divisions in the upcoming heating season. The results of that analysis are presented in Table 10. The projected requirements in each of the Company's divisions in January 1986 at the 60 degree day level are shown.

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76. 9 DOMSC at 199 (1982).
77. Forecast, page unnumbered.

Table 10
Bay State Gas Company
Cold Snap Analysis
January 1986

	Brockton	Lawrence	Springfield	Total
On-System Sendout				
60 Degree Days	102.9	47.6	86.3	236.7
Off-System Sendout	2.6	0.0	5.4	8.0
TOTAL SENDOUT				
60 Degree Days	105.5	47.6	91.7	244.7
PIPELINE MDQ	61.0	19.0	56.0	136.0
REQUIRED SUPPLEMENTALS				
60 Degree Days	44.5	28.6	35.7	108.7
AVAILABLE STORAGE CAPACITY				
LNG	808.0	13.0	1020.0	1841.0
Propane	132.3	24.5	163.3	320.1
SENDOUT CAPACITY				
LNG	51.0	19.0	55.0	125.0
Propane	39.0	22.0	49.0	110.0

The following use factors were used in the analysis (based on January 1986 Peak Day Forecast):

Heating Increment	1.5	0.7	1.2	3.4
Daily Base	12.6	5.3	13.4	31.3

The projected requirements are based on the Company's 1986 peak day heating and base use increments; the 60 degree day level was chosen as representative of a cold snap level. In fact, a cold snap consisting of a series of peak days is improbable. The Council instructs the Company to present a more realistic cold snap standard in the future at the time determined after consultation with the Council Staff. See Condition 11. Perhaps an appropriate standard would be one comparable to the actual two-week weather pattern which occurred during the 1981/82 cold snap.[78]

Analysis indicates that in the Brockton division the Company would require 44.5 MMcf of supplemental supplies on a 60 degree-day day. The Company could meet this requirement entirely with LNG vaporization. To meet ten days of sendout at this level would require that LNG inventories at 55 percent of capacity. Should inventory levels be lower, propane could make up the difference. The Company is able to vaporize propane at full capacity for over three days if storage is full, without replenishment.

At the 60 degree day level, the Lawrence division would require sendout daily of 28.6 MMcf of supplementals to meet peak day requirements. The division has vaporization capacity of 19 MMcf for LNG and 22 MMcf for propane, and storage capacities are 13 and 24.5 MMcf, respectively.

To meet cold snap requirements in Lawrence, the Company would need to vaporize propane up to the limits of storage (13 MMcf) and refill storage daily. The remainder would have to be met with LNG (6.6 MMcf). This dispatch would require that propane be refilled on a daily basis (nearly 16 truckloads) and LNG every other day.[79] An alternative dispatch would make use of greater daily quantities of LNG, reducing propane transportation requirements.

Because of the amount of LNG storage, the Springfield division is in the best position in terms of being prepared for meeting the requirements of a cold snap. At the 60 degree day level, Springfield requires 35.7 MMcf of daily sendout of supplementals to meet its requirements. Again, this could be met entirely with LNG. To meet ten days of sendout at this level, LNG inventories would need to be at only 35 percent of storage capacity.

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78. In its most recent decision involving Boston Gas Company in Docket No. 83-25, the Siting Council analyzed the gas supplies which were available to Boston Gas to meet a two-week cold snap similar to that experienced from December 31, 1980 to January 13, 1981. That particular cold snap contained 703 degree days, or an average of 50 degree days per day. The Siting Council believes a similar analysis would be appropriate for Bay State's future filings.
79. The propane contracts existing at the time of the filing provided for a total of 18 truck loads of propane per day. Deliveries were the responsibility of the supplier. Additionally, the Company, as of 1983, owned four trailer transports and leased a fifth. Whether these are used exclusively for transporting off-system volumes is not clear. These issues should be addressed by the Company in response to Condition 10.

This analysis does not consider several factors. It does not address the manner by which off-system customers request and receive firm and optional volumes of LNG and propane in fulfillment of their contract entitlements. This is an issue we are particularly interested in seeing the Company address in its response to Condition No. 10.

Secondly, it does not address the timing of DOMAC LNG shipments which would increase available inventories during a cold snap . The analysis also assumes that no best efforts delivery of storage gas will occur during the cold snap. Finally, we have not addressed the impacts of new projects, and attendant changes in city-gate capacities, nor of potential delays in new projects. Again, the Company should address all of these issues in its next filing.

V. Order and Conditions

The Council hereby APPROVES Bay State Gas Company's Second Supplement to its Second Long-Range Forecast and ORDERS, as CONDITIONS to approval:

1. That the Company present an analysis of commercial and industrial usage by SIC code. The study shall address those issues outlined in Section II.B.2b.

2. That the Company present a substantially improved forecast of load growth in the residential sector. At a minimum, the Company shall outline for the residential heating and non-heating classes the following information:

   - the total gross load projected to be added in each year and class;
   - the total load loss in each class and year due to conservation and to customer losses;
   - the total number of units of each type to be added and the estimated total load due to each;
   - the projected split between base and heating load in each year and class;
   - the projected distribution of base and heating load additions for each class across the year, at least at the seasonal level; and
   - average annual base and heating usage for all heating customers; new heating customers and all non-heating customers.

3. That the Company provide a substantially improved forecast of commercial and industrial load growth. At a minimum, the Company shall include for each year and class:

   - the projected total gross load additions;
   - the estimated load loss due to conservation and to business closings;

- the estimated base and heating load additions;
- the distribution of load additions, by base and heating, across the year, at least at the seasonal level; and
- a discussion of targeted growth by SIC codes in the commercial and industrial sectors.

4. That the Company discuss in detail the issue of seasonal and on-peak conservation. Additionally, the Company shall reflect forecasted conservation in customer use factors, and the projected number of new customers. The Company shall provide supporting documentation.

5. That the Company describe in detail its method of incorporating load growth projections into the forecast of normal year requirements, for each year and class, and at least broken out by season.

6. That the Company provide documentation on how it projects design year requirements. The Company shall provide all supporting documentation, including, but not limited to, forecasted heating increments and base use factors, by year, (and by class if the Company elects such manner to project design requirements).

7. That the Company develop and document a peak day forecast methodology which addresses the changing nature of its customer base. The Company shall specifically state and document all assumptions regarding peak day base and heating use factors and the effect of new customer and load additions on peak day sendout. The Company shall also address the issue of conservation on-peak.

8. That the Company outline the status of off-system contract renegotiations. The Company shall also continue to outline existing and projected off-system sales for each division, as well as off-system sales on peak.

9. That the Company discuss in detail its participation in all new gas supply projects with applications currently pending at FERC, or ERA. Bay State shall discuss its proposed entitlements under each proposal, the status of the proceedings, and alternative plans or contingencies should the project(s) be delayed beyond projected dates.

10. That the Company develop an appropriate cold snap standard reflecting a realistic weather pattern and demonstrate that it is able to meet cold snap conditions in each of its divisions in each year of the forecast.

11. That the Company meet with the Council Staff before June 1, 1985, to discuss compliance with these Conditions.

The Council acknowledges that satisfaction of all these CONDITIONS is unattainable before the filing of the next Supplement, which will be due September 3, 1985. The Council Staff and the Company shall reach agreement at the meeting convened pursuant to Condition No. 11 as to which Conditions shall be satisfied by next filing date. All Conditions, however, shall be satisfied in the Third Long-Range Forecast. The Siting Council shall have the discrection to modify the list of conditions (pursuant to meeting with the Company as required in Condition No. 11) upon a showing that the thrust of a condition can be more appropriately met in a different manner. However, any modification, including the reasons therefore, shall be documented.

James G. White, Jr.
James G. White, Jr.

Unanimously APPROVED by the Energy Facilities Siting Council on April 25, 1985, by those members and designees present and voting: Chairperson Sharon M. Pollard (Secretary of Energy Resources); Joellen D'Esti (for Secretary of Economic Affairs, Evelyn F. Murphy); Sarah Wald (for Secretary of Consumer Affairs, Paula W. Gold); Stephen Roop (for Secretary of Environmental Affairs, James S. Hoyte); Robert W. Gillette (Public Environmental Member); Joseph W. Joyce (Public Labor Member); Dennis J. LaCroix (Public Gas Member).

5/3/85
Date

Sharon M. Pollard
Sharon M. Pollard
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

Petition of the Nantucket Electric Company for Approval of its First Annual Supplement to its Second Long-Range Forecast and Electric Needs and Resources	EFSC Docket No. 83-28

PARTIAL FINAL DECISION

William S. Febiger
Hearing Officer

April 25, 1985

On the Decision:
Carolyn Ramm
Senior Counsel

I. Introduction

This Partial Decision deals with two aspects of the supply plan developed by Nantucket Electric Company ("Nantucket" or "the Company") in connection with its First Annual Supplement to its Second Long-Range Forecast of Electric Needs and Resources ("the Supplement"). These are (1) Nantucket's decision to acquire an additional 3.6 MW of generating capacity (at a site yet to be determined) in order to alleviate its current shortage of reserve capacity, and (2) the contingency plan it has developed to cope with any supply shortages which might occur prior to the time the new generating equipment can be installed. This Partial Decision also considers Nantucket's undertaking (pursuant to an agreement of all the parties to this proceeding reached in November 1984) to implement a conservation and load management program.

The Siting Council hereby APPROVES as part of Nantucket's supply plan the Company's intention to acquire additional capacity (site undetermined) and pursue a conservation and load management program, subject to the conditions hereinafter set forth. All other issues raised in Nantucket's Supplement are reserved for decision at a later date, following further adjudicatory proceedings.

II. Background, Purpose and History of Proceeding

A. Background

Nantucket is an investor-owned utility that provides electric service to the Island of Nantucket, exclusively. The Company is unique among Massachusetts electric utilities in the fact that it is not in any way interconnected to the New England Power Pool ("NEPOOL"). Nantucket is one of the smallest electric companies in the Commonwealth, having annual sales totalling approximately one-tenth of one percent of electric sales in Massachusetts as a whole.

Seven diesel generators with a total capacity of 19.95 MW provide power to the system from the Company's plant in downtown Nantucket. The units, installed between 1948 and 1978, range in size from 0.7 MW to 6.9 MW.

The Company's forecast of sales and peak loads through 2008 are documented in a report entitled "Development of a Master Plan" prepared by the consulting firm of Charles T. Main Corporation in May of 1981 ("the Main report") and updated in March of 1984. This update forecasts that Nantucket's annual sales will increase from 51,794 MWH in 1983 to 79,900 MWH in 1993. Summer peak load is expected to grow from 15.0 MW to 18.4 MW over the same period. The forecast continues to point up the concern expressed in the Siting Council's last decision that Nantucket will have inadequate reserve margin capacity -- based on loss of its largest generator (6.9 MW) -- without additional generation.

B. Purpose

In keeping with its statutory mandate "to provide a necessary energy supply for the Commonwealth," G.L. c. 164, Sec. 69H (emphasis supplied), the Siting Council has determined that certain aspects of Nantucket's supply plan require an immediate decision, even though adjudicatory proceedings concerning its demand forecast have not yet been concluded.

As discussed in detail below, the Siting Council is seriously concerned that during the summer of 1985 and in later years, Nantucket's ability to generate enough electricity to meet system load may be significantly impaired due to the decreasing size of its reserve margin.

Three concrete proposals to address this supply problem are currently before the Siting Council. Two of these - the acquisition of a new 3.6 MW generator and the implementation of a conservation and load management program - have been assented to by all of the parties and incorporated in separate settlement agreements. In order to encourage Nantucket to take immediate steps to implement these proposals, the Siting Council is approving them in this Decision. In the third area, the Siting Council is herein reviewing Nantucket's contingency plan, provided at the request of the Hearing Officer. Conditions are enumerated in Section II-3 below in order to ensure that Nantucket does in fact have an adequate and workable contingency plan.

C. History of the Proceeding

The procedural history of this docket is long and complex. On May 11, 1983, Nantucket filed its Supplement[1] with the Siting Council. This filing consisted of the original Main report and a petition setting forth information intended to satisfy the conditions upon which the Siting Council had approved Nantucket's preceding forecast in 1982 (8 DOMSC 257 (1982). The Siting Council proceeding that was thus initiated (and known as EFSC Docket No. 83-28) is still pending today. The present Partial Decision represents an effort to reach a final disposition of at least some of the issues raised therein.

The Siting Council received timely petitions to intervene in Docket No. 83-28 from the Attorney General of the Commonwealth of Massachusetts; a conservation organization known as the Nantucket Land Council ("NLC"); a group of individual customers of Nantucket styling themselves Worried Electric Consumers about Rates and the Environment ("WECARE"); and the Siting Council staff. After some preliminary debate over the propriety of these interventions, conducted through motions,

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1. Styled "Petition of the Nantucket Electric Company for Approval of its First Annual Supplement to its Second Long-Range Forecast of Electric Needs and Resources."

memoranda of law, and a prehearing conference, all of these intervenors were admitted as parties to the proceeding. Procedural Order, EFSC Docket No. 83-28, August 11, 1983.

Shortly after their admission as parties, the intervenors filed a Joint Initial Set of Information Requests, seeking detailed discovery relevant to Nantucket's demand forecast and supply plan. On October 5, 1983, Nantucket submitted a letter in which it refused to answer any of these information requests, on the general grounds that much of the information requested was available in the original Main report or in the record of Nantucket's rate proceeding then pending in the Department of Public Utilities ("D.P.U."), D.P.U. No. 1530; that the number of requests was excessive; and that the preparation of responses was unduly burdensome to Nantucket's employees. Two days later Nantucket filed an Addendum to its Supplement, which indirectly responded to a few of the intervenors' questions.

After a round of motions and memoranda arguing the propriety of the discovery requested by the intervenors,[2] the Hearing Officer ordered Nantucket to respond to all of the information requests, either by objecting specifically to individual information requests or by providing the requested information. Nantucket was also instructed to identify those requests that would be covered by an "update" to the Main report which it had recently commissioned and intended to file with the Siting Council. Procedural Orders, EFSC Docket No. 83-28, November 22, 1983 and November 30, 1983.

Meanwhile, the D.P.U. had become interested in Nantucket's reserve margin problems. In an order (D.P.U. 1530) dated November 30, 1983, the D.P.U. announced that it was commencing a proceeding of its own to review Nantucket's response to these problems, and ordered Nantucket to file a detailed direct case including: (1) an analysis of future demand levels; (2) a review of alternatives to its proposed acquisition of a new diesel generator; (3) a reliability study relating to various supply alternatives; and (4) a study examining the demand-side strategies of conservation and load management.

At a conference held December 8, 1983, the parties to the Siting Council supplement proceeding agreed to seek consolidation of the Siting Council and D.P.U. proceedings for purposes of hearing (though it was contemplated that each agency would compile its own record and issue its own decision on the issues with which it was concerned). On January 4, 1984, all of the parties filed their Joint Motion for Approval of Agreement Concerning Procedures for Review and Initiation of Joint Hearing with the Department of Public Utilities. The Hearing Officer granted this motion on February 2, 1984, contingent upon the D.P.U.'s concurrence, Procedural Order, EFSC Docket No. 83-28, February 2, 1984.

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2. Including a motion by WECARE for rejection of Nantucket's supplement if discovery was not forthcoming.

Subsequently, Nantucket filed with both the Siting Council and the D.P.U. the updated Main report (entitled "Evaluation of Future Capacity Additions") and the direct case which had been requested in D.P.U. 1530. All of the intervenors in the Siting Council proceeding petitioned to intervene in the new D.P.U. proceeding (D.P.U. No. 84-55) as well, and were accepted. On April 13, 1984, the D.P.U. issued an order assenting to the proposed consolidation of the hearings in the Siting Council and D.P.U. proceedings. Shortly thereafter the D.P.U. and the Siting Council issued identical orders establishing a procedural schedule for the remainder of the consolidated proceeding. The schedule contemplated that discovery would be finished by June 18, 1984, hearings by August, 1984, and briefing by September 14, 1984.

This schedule soon fell by the wayside as conflicts over discovery continued. Even now, a full year later, no hearings have taken place and there has been little progress in the case except with respect to the Company's provision of information. The intervenors filed their individual information requests in compliance with the schedule, whereupon Nantucket renewed its objections that the requests were too numerous, that answering them would be too burdensome, and that the information requested was available elsewhere. In a Procedural Order dated July 6, 1984, the Hearing Officer directed efforts by the parties responsive to the Company's concerns. However, no discovery was had during the summer of 1984.

At this juncture Nantucket also argued, for the first time, that the Siting Council lacked jurisdiction to review its plans to acquire additional generating capacity. The Company based its contention on the argument that the proposed generating facility was below jurisictional size limits; this contention was considered and rejected by the Hearing Officer in a Procedural Order dated July 6, 1984.

Over the summer of 1984, the parties met several times and succeeded in reaching a stipulation that Nantucket's purchase of a 3.6 MW diesel generator would be an "appropriate, prudent, and reasonably necessary response to the Company's current margin problem... ." Joint Motion of All Parties Requesting Approval of Partial Settlement and Agreement Concerning Scope of Hearings (August 8, 1984), at p.2. The stipulation further provided that the agreement as to need for the 3.6 MW generator would not bar scrutiny of its cost at a later date; that location issues are reserved as the subject of hearings in the proceeding; that the parties would continue negotiations on the issues of conservation, rate structure and load management; and that upon approval of the stipulation all information requests would be deemed withdrawn except those dealing with the location of the generator and, if no further settlement could be reached, those dealing with conservation, rate structure and load management. This stipulation was approved by the Siting Council Hearing Officer on August 23, 1984, and by the D.P.U. on August 30, 1984.

Thereafter, Nantucket filed a motion to sever the previously consolidated D.P.U. and Siting Council proceedings on the grounds that no disputed issues of common interest to the two agencies remained to be litigated. The Siting Council Hearing Officer later denied this motion, noting that the D.P.U. review did overlap its own and that Nantucket had not otherwise supported its position, Procedural Order, EFSC Docket No. 83-28, October 31, 1984.

In the meantime, several things had happened. The intervenors had once again filed information requests on supply issues. For the first time, Nantucket had filed objections to specific information requests, and begun to provide responses to uncontested information requests. The Hearing Officer had issued an order compelling responses to certain further information requests and disallowing others. Procedural Order, EFSC Docket No. 83-28, October 17, 1984. Finally, continuing negotiations had resulted in a proposed settlement of the conservation and load management issues agreed to in the August, 1984 stipulation. Under the settlement Nantucket would be permitted to collect $180,000 per year from its customers through fuel charge adjustments to fund certain specific conservation and load management programs.

After the proposed settlement was filed on November 8, 1984, the schedule was again delayed as the intervenors filed additional information requests on supply and demand issues. In response to Nantucket's objections that the requests on demand issues were precluded by the August, 1984 stipulation, the Hearing Officer placed restrictions on the scope of allowable demand discovery and disallowed a number of the intervenors' specific information requests. Procedural Order, EFSC Docket No. 83-28, December 28, 1984.

Nantucket then filed a motion to combine the pending proceeding with its next Long-Range Forecast, which it volunteered to file in April, 1985, over eight months before its was due. During deliberation on the motion, Nantucket completed filing answers to demand discovery which had previously been allowed by the Hearing Officer. The Hearing Officer denied the motion to combine in a procedural order issued February 13, 1985.

Uncertain that the D.P.U. remained interested in conducting joint hearings with the Siting Council, the Hearing Officer in his order of February 13, 1985, issued a schedule for the remaining demand-side proceedings in the Siting Council docket. In the same order the Hearing Officer expressed the intention of drafting a partial decision for the purpose of disposing of the issues settled in the two 1984 stipulations and certain other supply-side issues. The present Partial Decision represents the fulfillment of that intention.

On March 29, 1985, the D.P.U. issued an order in D.P.U. No. 84-55 terminating its investigation of Nantucket's reserve margin problem, finding that the question of siting Nantucket's new generator would be comprehensively dealt with in the Executive Office of Environmental Affairs' review of the Environmental Impact Report ("EIR") which it had ordered Nantucket to prepare, and which was filed March 25, 1985.

The Siting Council intends to proceed with its independent review of the demand issues raised in Nantucket's supplement.

II. The Reserve Capacity Situation

A. Background

In EFSC 81-28, the Council found that a Company in Nantucket's situation -- an isolated system without the security of an interconnection to other utilities -- would require a reserve capacity equal to the capacity of its largest unit, also known as a first contingency capability.[3] 8 DOMSC at 268. Nantucket's first contingency reserve requirement is based on its 6.9 MW Unit 7.

Installed in 1978, Unit 7 brought the system's capacity to 20.2 MW (later rerated to 20.0 MW). The disproportionately large size of this unit, however, meant that peak load could not exceed about two thirds of system capacity without exceeding the first contingency capability. Simply stated, if Nantucket were to lose its largest unit, it would be unable to meet an instantaneous demand greater than 13.1 MW.

In 1982, four years after Unit 7 was installed, the summer peak, 13.8 MW, exceeded the first contingency capability. In 1983, the summer peak reached a record 15.0 MW. In 1984, while the number of customers continued to rise, the summer peak slid 4 percent to 14.4 MW -- still more than 1 MW above the first contingency capability.[4]

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3. The current Forecast continues to assume that a single contingency reserve capability should be maintained as a "minimum reserve level" applicable for the system. See C.T. Main Update, p. 5-14. The Company's filing includes a review of various deterministic and probabilistic reliability criteria which could be considered for the system. The Company's consultant, C.T. Main, recommends that the Company consider adopting a higher reserve capability criterion in the near future, based on "loss of the largest unit plus one of the smaller units." C.T. Main Update, p. 5-16. The question of reserve capability has been the subject of intervenor discovery at different stages of the proceeding. Certain information requests on the subject were included in the Attorney General's most recent set of discovery (December 12, 1984), to which the Company objected based on its view of terms in the August, 1984 Settlement. These information requests were disallowed by the Hearing Officer. See Procedural Order, EFSC 83-28, December 28, 1984. The EFSC reserves the right to address the Company's choice of reserve criterion in future proceedings.
4. The Company had projected a 14 percent drop in its summer 1984 peak load -- to 12.9 MW. It may be noted that this forecast included an adjustment for estimated water heater time clock controls, as they affect peak load. C.T. Main Update, P. 4-16. In addition, the Summer 1984 peak estimate assumes the Company's resetting of existing time clocks, which was completed in May, 1984. See Response to Attorney General's Information Request 3 (December 3, 1984).

An even more dramatic indicator of the worsening reserve margin problem is the increasing number of days in the last two summers on which the Company's peak load exceeded its first contingency capability. In part reflecting a 0.2 MW downrating of system capacity (from 20.2 MW to 20.0 MW), the number of days on which this occurred jumped to 17 in Summer, 1983. Then, despite a decline in actual peak load, the number of days on which peak demand exceeded the first contingency capability more than doubled, amounting to 35 days in Summer, 1984. Response to WECARE Information Request 76 (propounded December 12, 1984).

These circumstances have enhanced the chance of experiencing periods of insufficient capacity to meet system load -- due solely to the loss or unavailability of Unit 7 (with Units 1 through 6 available). Indeed, outage data available through 1983 show that such an insufficiency in fact did occur, on August 12, 1983, for the only time that year and the first time since Unit 7 was installed. Response to DPU Hearing Officer's Information Request 6, D.P.U. No. 84-55, June 19, 1984. (1984 outage data have not been obtained.)

The previous Siting Council Decision (EFSC 81-28, dated November 29, 1982), recognized that the Summer 1982 system peak had in fact exceeded Nantucket's first contingency capability.[5] Accordingly, the Council ordered the Company to provide within 120 days either a detailed report of how it planned to secure, prior to July 1, 1983, a reserve margin equal to the capacity of its largest unit or a satisfactory explain why it felt that it would be unable to do so. 8 DOMSC at 273. Company officials met with representatives of the Siting Council on February 8, 1983, to discuss the Company's plans to acquire additional generating capacity. The Company then submitted an interim report (in response to the Council's order) stating its intention to acquire a 6.0 MW generator. Letter to EFSC Hearing Officer, May 4, 1983. On May 10, 1983, Nantucket filed its petition in the current proceeding proposing the acquisition of capacity.

For the remainder of the forecast period, the Company projects continued growth in sales and resumed growth in peak load. The 1993 peak load forecast by the Company is 18.4 MW -- 4.0 MW above the actual Summer 1984 peak load.[6]

The Siting Council has not yet completed its review of the Company's demand forecast methodology and data. The Council cannot therefore draw conclusions as to the accuracy or reasonableness of Nantucket's forecast of system requirements. (These issues are still being adjudicated as part of the demand side of this proceeding.)

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5. Based on the current rated capacity of 20.0 MW. At the time of EFSC 81-28, Nantucket's rated capacity was 20.2 MW, and the first contingency capability was 13.3 MW.
6. The forecast of system requirements does not reflect implementation of conservation and load management programs recommended as part of a proposed settlement in this proceeding. See infra, Section III.

However, due to the current situation in which recent peak loads have exceeded the system's first contingency capability by as much as 1.9 MW (15 percent), the Siting Council accepts that the Company already has a reserve-capacity problem which it must address in the short term.

B. Addressing Near-Term Deficiencies

The upcoming summer season marks the third since the Council's last decision in November, 1982. The concerns expressed by the Council in 1982 regarding how the Company planned to meet reserve requirements in Summer 1983 still loom for Summer 1985, and possibly for Summer 1986. The Council must address the actions that should be taken in order to minimize adverse effects of near-term reserve deficiencies.

The Company has been directed on several occasions -- both in the current proceeding and in the last Siting Council decision -- to discuss its plans for addressing near-term reserve deficiencies. Nantucket has responded to date with a basic proposal to acquire additional capacity, along with information on Nantucket's recent outages and on the Company's current contingency plans to guide its responses to such outages.

1. The Settlement on Capacity

To help resolve the Company's reserve-margin problem, the parties agreed upon and filed in August, 1984 a stipulation as to Nantucket's need for an additional 3.6 MW of capacity. See *supra*, Section I-B. The stipulation also briefly addressed -- essentially deferred -- a number of other issues related to Nantucket's supply plan.

After the stipulation was approved by the EFSC Hearing Officer and the D.P.U., the parties continued meeting in an effort to reach further agreement in one of the deferred issue areas -- conservation, rate structure, and load management. A follow-up stipulation on conservation, rate structure, and load management then was filed on November 6, 1984. See *infra*, Section III.

The cornerstone of the August 1984 settlement is an agreement that the purchase and installation of a 3.6 MW diesel generator is an appropriate, prudent and reasonably necessary response to the Company's current reserve-margin problem. The stipulation goes on to reserve the question of where the additional capacity should be located as the subject of hearings in the joint proceeding.

Expanding beyond these basic agreements, the stipulation includes a number of specific qualifications and related provisions concerning the current and future reviews. Namely, it:

1. preserves the rights of all parties to review costs (of needed capacity) in future proceedings;
2. leaves unaddressed methods of resolving *future* reserve margin problems;
3. recognizes that the EFSC decision may address demand;

4. recognizes that conservation, rate structure and load management may be effective techniques for addressing demand;
5. recognizes the importance of operating and maintenance procedures for ensuring supply reliability and minimizing need for future capacity additions;
6. recognizes need for expeditious adjudication of the question of location, consistent with rights of parties; and
7. provides for withdrawal of prior information requests in the present proceedings except those related to location.

The Council finds that the stipulation constructively addresses the Company's reserve-margin problem, as required in EFSC 81-28. Additionally, the various additional provisions of the stipulation also further purposes of EFSC forecast review.

The Council believes that additional attention should be focused on steps needed to minimize the adverse effects of reserve deficiencies in the near term. (See the following subsections.) With that qualification, the Council approves the stipulation of capacity as part of Nantucket's supply plan.

2. Lead Time to Acquire Additional Generation

Given the importance of additional capacity for Nantucket, the question arises as to how quickly it can be acquired. The Company has maintained that a lead time of eleven months is required for its supplier, Cooper Energy Services, to assemble and deliver the proposed new diesel generator. Letter to EFSC Hearing Officer (complying with Council's Order), May 4, 1983. Response to Hearing Officer's Information Request 1 (February 13, 1985). Additional time also may be required for installation of the generator following delivery.

Nantucket has provided no information as to whether competing suppliers could provide comparable equipment under a significantly shorter lead time. The Company once did state its position that a used generator (which could possibly be available immediately) should not be considered. Letter to EFSC Hearing Officer, May 4, 1983.

Regardless of the length of lead time needed for assembly, a major step in obtaining a generator is to place an order. In the Company's view, a principal prerequisite for the placement of an order is receipt of any prior approval needed to ensure the Company's ability to recover its cost through rates. Response to Hearing Officer's Information Request 2 (February 13, 1985).

Indeed, until recently, the D.P.U. -- the agency with responsibility for determining issues of cost recovery -- was reviewing the Company's proposal to acquire and install a 3.6 MW generator at the airport site. That review was closed March 29, 1985, without making findings on the issue of location. Months earlier, the D.P.U. (and the EFSC Hearing Officer) already had approved the selection of size and type of equipment, based on the settlement agreed to by all parties in August, 1984. See *supra*, Section I-C.

Other regulatory reviews besides that of the D.P.U. are also pending. A number of state level reviews, including the full EFSC supply and demand review, the MEPA review, and possibly one or more environmental permit reviews, are yet to be completed.[7] Development of complete equipment specifications indeed may need to await receipt of all necessary regulatory approvals concerning siting, environmental protection measures, and operating procedures.

However, it is significant that the Company now has all the regulatory support it can expect for its selection of size and type of equipment -- both from the D.P.U. and, with this Order, the EFSC. The Council is concerned that continued delays in the Company's placement of an order may result in the current reserve problem extending into or beyond Summer, 1986. Assuming the indicated eleven-month lead time (and ignoring any additional lead time needed for the on-site installation and start up work), the Company would need to place an order by August 1, 1985 at the latest to allow delivery and installation by July 1, 1986.

Accordingly, the Council directs the Company to carefully review, with its chosen supplier and alternative suppliers, the critical time lines that apply to the placement of an order so as to ensure installation of additional generating capacity for use by July 1, 1986, or earlier. In particular, the Company should clarify the possibilities for finalizing the equipment specifications in one or more later stages, following an initial order, and consider the availability of comparable equipment from competing suppliers under more favorable time lines.

As a condition for approval of the settlements in this proceeding to date, the Company shall review, and report upon to the Council by May 9, 1985, the critical time lines for ordering generating equipment. The Council will provide written confirmation when the Company has satisfactorily complied with this condition. Before it issues such confirmation, the Council may request a meeting with the Company to discuss the review, and the parties to the current proceeding will be invited to attend such meeting.

3. Contingency Planning

In June, 1984, at the request of the Hearing Officer, Nantucket provided a copy of its contingency plan for responding to conditions of insufficient generating capacity. Aimed at multiple as well as single unit outages, the plan calls for two levels of response:

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7. With regard to the airport site, there is the additional concern that negotiations for purchase or lease of the site need to be completed. See Nantucket Electric Company's Objections to Discovery by WECARE and Nantucket Land Council, December 19, 1984, P.10 (re: Nantucket Land Council's Information Request 6, December 3, 1984)

1. Initially, rotate cutoffs of power for 15-20 minute intervals to three feeder circuits in turn.

2. If the problem persists, disconnect certain customers as necessary -- first, the Boat Basin; second, Nantucket Cable Vision's main amplifier; third, customers with emergency generators who agree to remain on their own power.

According to outage records available for the years 1974 through 1983, it appears the Company has relied on voltage reductions, usually of one-to two-hours duration, to address system capacity shortfalls. This apparently was done for the August 12, 1983 unavailability of Unit 7, as well as for a number of earlier second contingency outages experienced since Unit 7 came on-line, which typically involved simultaneous unavailability of Units 7 and 6.[8] Response to DPU Hearing Officer's Information Request 6, DPU 84-55, June 19, 1984. The measures outlined in the contingency plan had not been used, based on the 1974-1983 records.

With the 1985 summer season now less than three months away, the Council is concerned about the adequacy of the Company's preparation for capacity shortfalls due to outages. It is not clear how large or how long a system insufficiency would be required to cause the Company to begin implementing its contingency plan. The contingency plan provides no estimates of the level of capacity shortfall that could be offset by each of the steps outlined in the plan.

The plan gives no indication of any contact with identified customers having emergency generators concerning the plan. Thus, it is not clear how the Company would contend with a shortfall that continued for a long time.

As a condition for approval of Nantucket's plans for addressing its reserve margin problem, the Council directs the Company to provide, by May 17, 1985, a more detailed contingency plan.

The plan should identify the Company's assumptions as to: (1) the extent of shortfall that can be offset by successive measures (i.e., reducing voltage, rotating cut-off of power, shedding particular loads), and (2) the lengths of time over which respective measures can reasonably be sustained. The Company also should provide discussion of the contact it has had (or expects to have) with government officials and customers who voluntarily or involuntarily would lose power under any of the plan's measures, and an indication of the responsiveness of

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8. In the recently completed Draft Environmental Impact Report, the Company mentions yet another and more drastic contingency response -- leasing portable emergency generators. Draft <u>Environmental Impact Report, 3.6 MWe Diesel Generator Facility</u> (EOEA No. 5369), March, 1985, p. VII F-7.

such officials and customers to the plan. The Council will provide written confirmation when the Company has satisfactorily complied with this condition. Before it issues such confirmation, the Council may request a meeting with the Company to discuss the contingency plan, and the parties to the current proceeding will be invited to attend any such meeting.

III The Follow-Up Settlement -- Conservation, Rate Structure and Load Management

In November, 1984, the parties agreed to a follow-up stipulation, under which Nantucket would implement forthwith a program to bring about increased conservation and load management. The Company would designate a conservation coordinator, and initially, until its next rate case before the D.P.U., would be permitted to collect $180,000 from its customers to fund the program.

According to the specific program elements identified in the stipulation, Nantucket would:

1. make conservation materials available to the customers at discount prices;
2. provide free installation of weatherization materials for lower-income customers;
3. make technical energy audits available to large commercial customers;
4. require certificates of lighting and thermal efficiency from new customers;
5. offer rebates on certain energy-efficient appliances;
6. demonstrate for its customers a summer-only solar water heating system; and
7. require a specified efficiency level for new water-heating customers.

In support of the stipulation, the parties developed estimates of direct and indirect program costs, and total estimates of energy saved for four of the seven programs. Lasting three years, the overall program would have potential total indirect costs of $112,309[9] and total direct costs of $173,930. For four programs accounting for $138,094, or 79 percent, of total direct costs, total savings of 5243 MWH would be achieved -- an average direct program cost of 2.6¢ per KWH (see Table 1).

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9. Initially, and evidently until such time as the costs are filed in a rate case, the indirect costs would be only $6,105. The additional $106,204 in potential indirect costs would provide for hiring an energy conservation coordinator; (for the three years of the program), should experience indicate the need for additional personnel.

Table 1
Costs and Energy Saved
Selected Proposed Conservation Programs

Program	Estimates Direct Cost ($)	Estimated Total Energy Saved (MWH)
Discounted Conservation Materials	59,381	1,080.6
Installations - Low-Moderate Income Residents	38,070	352.6
Refrigerator and Freezer Rebates	35,333	2550.0
Water Heater Efficiency Standards	5,310	1260.0

Source: Stipulation, November 6, 1984, Appendix A

The follow-up stipulation clearly represents a good beginning for a utility of Nantucket's size -- outlining a broad implementation plan covering different kinds of conservation initiatives. While the stipulated energy savings and cost estimates are well researched, they are based of course on experience elsewhere. Because Nantucket's customer base is relatively unique, it is difficult to know how reliable such estimates are for Nantucket's service territory.

The Council believes it is important for Nantucket to collect accurate data on the implementation, performance and impacts of its conservation and load management programs. Such data, along with possible improvements in the Company's demand forecasting and related data base development, could enhance the Company's ability to evaluate prospective conservation and load management programs in the future.

The D.P.U. has declined to approve the stipulation's provision for recovery of program costs outside the context of a rate case. Order, D.P.U. No. 84-55, March 29, 1985. However, at least one program -- lighting and thermal efficiency standards -- has no direct cost and minimal indirect cost, and thus could be implemented immediately.

The Council agrees with the parties that the stipulated programs represent an appropriate plan to guide Nantucket's conservation and load management efforts in the upcoming years. The Council therefore approves the settlement and directs the Company to report, in its next filing, on its further evaluations, plans and progress regarding conservation, rate structure and load management.

IV. DECISION AND ORDER

The Council hereby APPROVES as part of Nantucket Electric Company's supply plan its acquisition of additional capacity (site undetermined) under the terms of the joint motion of the Parties of August, 1984 and its implementation of a conservation and load management program under the terms of the stipulation of the Parties of November, 1984, such approval being subject to the following conditions:

1. The Company shall review, and report to the Council by May 9, 1985, on critical time lines for ordering generating equipment. The Council will provide written confirmation when the Company has satisfactorily complied with this condition. Before it issues such confirmation, the Council may request a meeting with the Company to discuss the review, and the parties to the current proceeding will be invited to attend such meeting.

2. The Company shall provide, by May 17, 1985, a more detailed contingency plan. The plan should identify the Company's assumptions as to: (1) the extent of shortfall that can be offset by successive measures (i.e., reducing voltage, rotating cut-off of power, shedding particular loads) and (2) the lengths of time over which respective measures can reasonably be sustained. The Company also should discuss the contact it has had (or expects to have) with government officials and customers who voluntarily or involuntarily would lose power under any of the plan's measures, and an indication of the responsiveness of such officials and customers to the plan. The Council will provide written confirmation when the Company has satisfactorily complied with this condition. Before it issues such confirmation, the Council may request a meeting with the Company to discuss the contingency plan, and the Parties to the current proceeding will be invited to attend any such meeting.

3. The Company shall report in its next filing on its further evaluations, plans and progress regarding conservation, rate structure and load management.

William S. Febiger

William S. Febiger
Hearing Officer

Unanimously APPROVED by the Energy Facilities Siting Council on April 25, 1985, by those members and designees present and voting: Chairperson Sharon M. Pollard (Secretary of Energy Resources); Joellen D'Esti (for Secretary of Economic Affairs, Evelyn F. Murphy); Sarah Wald (for Secretary of Consumer Affairs, Paul W. Gold); Stephen Roop (for Secretary of Environmental Affairs, James S. Hoyte); Robert W. Gillette (Public Environmental Member); Joseph W. Joyce (Public Labor Member). Ineligible to vote - Dennis J. LaCroix (Public Gas Member).

May 3, 1985
Date

Sharon Pollard
Sharon M. Pollard
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Fitchburg Gas and Electric Light Company for Approval of the Third Supplement to the Second Long-Range Forecast of Natural Gas Requirements and Resources	Docket No. 84-11(A)

Final Decision

James G. White, Jr.
Hearing Officer

The Energy Facilities Siting Council APPROVES subject to CONDITIONS the Third Supplement to the Second Long-Range Forecast of natural gas requirements and resources of Fitchburg Gas and Electric Light Company ("Fitchburg" or "Company"). This Supplement covers Fitchburg's projections through the 1988-89 split year.

At the outset, the Siting Council acknowledges the improved documentation on the sendout portion of the current Supplement. The Company's effort in upgrading its documentation is apparent. The Siting Council looks forward to cooperating with Fitchburg toward improvements in the Company's methodology for forecasting firm seasonal and peak day sendout requirements.

I. Procedural History

Fitchburg filed the current Supplement on July 17, 1984. In accordance with directions of the Hearing Officer, Fitchburg provided notice of this adjudication by newspaper publication and posting of the formal Notice in Town Halls in Fitchburg's service territory. The Hearing Officer granted the Petition to Intervene of Citizens Energy Corporation ("Citizens Energy") which filed a timely Petition to Intervene.

Fitchburg filed responses to three sets of information requests of the Siting Council Staff. The Siting Council appreciates the Company's efforts in preparing the responses which were thorough and timely-filed.

The record in this proceeding is composed of the responses to the three sets of information requests, and certain responses of Fitchburg to information requests of Citizens Energy in Department of Public Utilities No. 84-145.[1]

II. Background

Fitchburg serves approximately 15,000 firm customers in Fitchburg and the towns of Ashby, Townsend, Westminster, and Gardner, including roughly 10,000 residential heating customers, 3800 residential non-heating customers, 950 commercial customers, and 95 industrial customers.

Fitchburg's total actual firm sendout in the 1983-84 split year was 2286 MMcf, up from 2222 MMcf in the 1982-83 split year, or an increase of approximately 2.9 percent. Total firm normalized sendout decreased, however, by roughly 2.1 percent in the same period. Fitchburg's

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1. At the prehearing conference on October 16, 1984, Citizens Energy Corporation ("Citizens Energy") and the Company agreed that Citizens Energy would not submit information requests in this proceeding except to request an update or clarification to discovery responses provided by the Company to Citizens Energy in the then ongoing Fitchburg Gas and Electric Light Company rate case at the Department of Public Utilities, D.P.U. No. 84-145.

historical data show that total firm normalized sendout increased by approximately 2 percent between the 1979-80 split year and last year.

Table 1 shows the normalized sendout by customer class and season for the 1983-84 split year, and the corresponding projections for 1988-89 (See Supplement at 17; and Tables G-1 through G-5):

Table 1

	1983-84 (MMBtu) Normalized Sendout				1988-89 (MMBtu) Projected Sendout			
	Non-Heating Season		Heating Season		Non-Heating Season		Heating Season	
Residential								
Heating	408.0	(54.7%)	866.0	(55.0%)	447	(54.7%)	969	(55.0%)
Non-Heating	65.2	(8.7%)	82.5	(5.2%)	71	(8.7%)	92	(5.2%)
Commercial	137.4	(18.4%)	270.4	(17.2%)	150	(18.4%)	303	(17.2%)
Industrial	117.8	(15.8%)	199.7	(12.7%)	129	(15.8%)	224	(12.7%)
Company Use/ Unaccounted	17.6	(2.4%)	155.8	(9.9%)	20	(2.4%)	174	(9.9%)
Total Firm Sendout	746.0	(100.0%)	1574.4	(100.0%)	817	(100.0%)	1762	(100%)

Whereas the Company had been in a "no-growth" posture in the recent past, Table 1 reflects the Company's stated goal of marketing volumes of pipeline gas currently not utilized. See discussion <u>infra</u>. Fitchburg has targeted growth increments of 35 MMcf for 1985-86, and 70 MMcf for each of 1986-87, 1987-88, and 1988-89, for a total goal of 245 MMcf, or a projected total increase of 10 percent in total firm sendout over the forecast period.

Table 1 also reflects the Company's statement that it "anticipates that there could be a slight change between classes during the forecast period, but for forecasting purposes, it is assumed that the changes would not be significant among the classes" (Supplement at 14).

As indicated in Table 1, residential customers account for over 60 percent of total firm sendout. Nearly 55 percent of firm sendout is accounted for by residential heating customers alone. The commercial class accounts for an additional 17 to 18 percent. In these classes, heating season sendout almost doubles the non-heating season sendout. Also, the firm industrial class heating season sendout is almost twice the firm non-heating season sendout.

III. Previous Conditions

The Siting Council imposed two conditions in its last decision, 10 DOMSC 181, 202 (1984):

1. Within ninety days, provide a compliance plan for submitting improved documentation for future forecasts.

2. Include in its next Supplement, a discussion of the reliability of full underground storage quantities during the heating season.

Pursuant to Condition One, the Siting Council Staff met with Company representatives on April 25, 1984, to discuss ways to improve documentation. Fitchburg's documentation of the sendout portion (particularly with respect to weather data and historical data) of the Supplement is greatly improved, and the Council finds that Condition One has been satisfied.

In response to Condition Two, Fitchburg has incorporated statements of "confidence" in the best-efforts delivery of storage gas during the heating season (Supplement at 19). As discussed infra, the Siting Council will require a more in-depth analysis of transportation of storage gas.

IV. Sendout Forecast

A. Discussion of Methodology

Fitchburg's basic methodology for projecting sendout requirements is unchanged since last year. However, the sendout portion of Fitchburg's Supplement displays enormously improved documentation as well as the incorporation of the average of Worcester-Bedford weather data.

In the current Supplement, Fitchburg uses a normal year of 6773 degree days based on the arithmetic average of 20 years of Worcester-Bedford degree day data from 1964 through 1984 (Appendix A to Supplement). The historical data in the current filing also has been "normalized" using the new weather data. The use of the average of Worcester Weather Station and Bedford Airport data represents a change from prior filings in which Fitchburg used various combinations of Fitchburg and Bedford data.[2] The Siting Council finds the change to be appropriate.

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2. Last year Fitchburg used Bedford Airport data, Docket No. 83-11A. And previously, Fitchburg had utilized Company weather data (Clinton weather adjusted to approximate Fitchburg conditions) for historical portions of its filings, and Bedford Airport data for its projections. Docket No. 81-11, 8 DOMSC 276 (1982).

In projecting normal year sendout requirements, Fitchburg basically uses the data from the most recent split-year, and derives system-wide base-load and space heating increments, for both the non-heating and heating seasons (Supplement at 15).[3]

For the 1984-85 split-year, Fitchburg assumed its "no-growth" policy would continue. Therefore, the projection of heating and non-heating seasonal sendouts for 1984-85 was the simple product of the derived base and heating factors and the normal and design weather standards. Thus, the 1984-85 system projection essentially was the result of normalizing 1983-84 data on a system-wide basis.[4]

For each of the ensuing years, Fitchburg allocates the targeted system market growth in sendout into the heating and non-heating season according to the historical (1983-84) relationship in sendout between these seasons - 68 percent in the heating season and 32 percent in the non-heating season (Supplement at 14-17). Fitchburg allocates the projected sendout to customer classes according to the 1983-84 percentage contribution of each class. Finally, Fitchburg states that "[h]istorical data was then used to develop projected customer use factors" (Supplement at 14).

The growth in the number of customers is determined primarily by available supply. Thus, while the number of residential customers increased in the past few years, the weather-corrected sendout did not increase during the no-growth period (Response to Information Request SO-1). Also, the Company does not have documentation on anticipated industrial and commercial development which is likely to result in addition of gas customers during the forecast period (Response to Information Request SO-6).

The Company has not provided adequate documentation on the derivation of customer use factors. In response to an information request, Fitchburg expressed reasons for projecting a decrease in residential split-year base use and a slight increase in the split-year heating use per customer per degree day (Response to Information Request SO-3).

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3. An examination of Supplement Table G-5, "Total Firm Company Sendout," reveals that the projected normal year sendout for 1984-85 was not the same as the normalized 1983-84 data. The difference could result from application of the derived system factors or partially from the normalization.
4. Fitchburg has indicated previously that determining base load and heating increments by using August sales data divided by the average number of monthly customers (over a split-year) is less exact because of the embodied assumption that August sales include no temperature-sensitive contributions (Response to Information Request SO-10, Docket No. 83-11A).

Fitchburg's design year projections are derived in the same way as for a normal year only using the design weather standards. Fitchburg assumes that all additional sendout will take place in the heating season. Thus, the projected system heating-season design-year sendout is simply heating season system-wide base load plus the product of a greater number of degree days and the system space-heating increment.

The peak day methodology is simpler yet. For 1984-85, Fitchburg simply adds the system daily base-load factor to the product of the system space-heating increment and the peak day weather standard. Fitchburg's projection of peak day sendout in the following years assumes that peak day sendout will grow by the same percentage as total system growth. Thus, (Supplement at 18):

1984/1985	Peak Day	19,917 MMBtu
1985-86	Growth	1.5% (299 MMBtu)
1985/1986	Projected Peak	20,216 MMBtu (19,917 + 299)
1986-87	Growth	3% (598 MMBtu)
1986/1987	Projected Peak	20,814 MMBtu (20,216 + 598)

B. Analysis of Methodology

Last year, the Siting Council stated that the "Company's forecast appears to be an adequate basis for supply planning," 10 DOMSC at 189. While that statement held true during the Company's recent "no-growth" period, the Siting Council feels that Fitchburg should begin development of a forecast methodology which will allow projections to reflect changing customer usage patterns across and within classes during the coming period of system growth, with the projections to be used as a planning device in analyzing system growth and supply options.[5]

The Siting Council believes the Company's methodology does not appropriately link historical data to future projections. The historical data on customer base and heating use factors are not used to project future requirements. Rather, future requirements are derived by a system-wide regression of the actual sendout during the most-recent historical split-year. Also, it is not clear to the Siting Council that the Company's assumption that the relative sendout requirements among customer classes will remain constant constitutes an appropriate projection method in the absence of documentation that the relationship will hold steady during the forecast period. And, this assumption does

5. Recently, the Siting Council issued a decision on Bay State Gas Company's ("Bay State") most recent Supplement. Bay State Gas Co., 12 DOMSC __, Docket No. 83-13 (April 25, 1985). Fitchburg's sendout methodology is similar to Bay State's and the Siting Council recommends that Fitchburg review the Bay State decision, in addition to the discussion contained herein, for guidance on how the Company might improve its methodology to address the Council's concerns.

not allow the Company to adjust its projections for known changes in sendout requirements for particular classes.[6]

The method of projecting peak day requirements also is troublesome. The methodology does not account for the possibility that heating use patterns may vary according to the degree days experienced - i.e., that heating use per degree day may increase during extremely cold days. Secondly, given the Company's use of its peak day capabilities as a guide to controlling growth, use of a system-wide peak based on the most recent historical split-year, would not appear to account for relative and known changes in the Company's customer mix essential to projecting peak day requirements.

The Siting Council views these methodological problems with concern, which concern would be more serious in the absence of the Company's obvious and significant efforts in improving the documentation in the current Supplement.

The Siting Council believes that Fitchburg should take steps in upcoming filings to address these concerns about the sendout methodology. Accordingly, the Siting Council will require the Company to meet with the Council Staff for the purpose of cooperating toward future improvements in the Company's sendout methodology. This requirement is affixed hereto as Condition Four.

V. Resources and Facilities

In the past, the Council has focused primarily on a gas company's ability to meet the requirements of its firm customers in reviewing that company's supply plan. A company's ability to meet firm peak day and normal and design weather requirements was the Council's major supply concern. In the past, the Council generally has not compared the costs of gas supply alternatives.

With a range of supply alternatives currently available at different prices, deliverability levels, and contract terms, the Council now must attempt to ensure a gas company's choice of supplies is consistent with the Council's mandate to ensure "a necessary energy supply with a minimum impact on the environment at the lowest possible cost." Mass. Gen. Laws Ann. ch. 164, sec. 69H (emphasis supplied).

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6. For example, in Docket No. 83-11A, the Fitchburg projected a substantial decline in sales to dual-fuel customers due to anticipated loss of several customers. Regardless of whether that projection was accurate at the time, the Company actually experienced a 50 percent increase in sales to dual-fuel customers from 1983 to 1984, from approximately 100 MMcf to 145 MMcf (Response to Information Request SO-5). The Company estimates 1985 sales to dual-fuel customers at 148 MMcf. (Id.)

The Council's task in observing its mandate is very complicated. The Council recognizes that a company's supply planning process is continuous, and that tradeoffs may exist between the reliability, cost and environmental impact of different supply sources. Further, the Council recognizes that a company's supply decisions are based on the information available and supply situation existing at the time the Company's management makes the decisions. Thus, each Company's supply plan will be different, and the Council will attempt to recognize the unique factors affecting the particular company under review. In the future, the Council will attempt to review each company's basis for selecting a supply alternative or the company's decision-making process to ensure that the company's decisions are based on projections founded on accurate historical information and sound projection methods.

In reviewing Fitchburg's current Supplement, the Council has examined, as before, the adequacy of Fitchburg's supplies to meet firm requirements under normal and design weather conditions, and peak day and cold snap conditions. The Council generally is satisfied that Fitchburg has sufficient supplies under these conditions. To the extent possible based on the existing record, the Council has reviewed Fitchburg's supply plan to determine whether the Company's plan ensures a necessary supply at the lowest possible cost.

As discussed infra, the Siting Council supports Fitchburg's apparent movement toward lower cost pipeline supplies and away from supplementals. The Council hopes to undertake a more in-depth review in future proceedings.[7]

In regard to its facilities, Fitchburg indicates that once firm pipeline supplies are increased, system improvements would be required to construct a pipeline loop to Gardner to allow the Company to improve reliability and increase market share (Supplement at Table G-21). The Tennessee take station is in Lunenburg, as is the propane plant. The current Supplement reflects the Company's intention to build a 9.65-mile, 10-inch high pressure pipeline, presumably to allow transportation of gas west toward Gardner. The pipeline would constitute a "facility" under Mass. Gen. Laws Ann. and would require the Siting Council's approval prior to construction.

In response to an information request, Fitchburg has submitted three maps of its gas service territories reflecting eight areas on low-pressure lines where no new load is to be added (Response No. 2 to

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7. The Council is unable to draw definite conclusions on whether Fitchburg's supply plan observes the least cost mandate consistent with providing reliable supplies. The Council's inability on this point derives both from the standards applied in past supply plan reviews occuring under different supply availability circumstances, and the level of information contained in the current Supplement. The Council at this point does not suggest an overall deficiency in the Company's supply planning. Rather, the Council is providing notice of the intended scope of future proceedings and of the type of information which the Council will require.

Third Set of Information Requests). The present record does not indicate whether these limitations result from the operational characteristics of the distribution system, or possibly from supply limitations. Nor does the record reflect whether the loop to Gardner would improve service reliability or allow growth in all the constrained areas. The Siting Council requests Fitchburg to discuss in its next supplement the status of service to those areas presently constrained and the Company's efforts to improve the system's operational characteristics.

A. Tennessee CD-6 Contract

Since last year's filing, Tennessee Gas Pipeline Company ("Tennessee") has filed with the Federal Energy Regulatory Commission ("FERC") a certificate application to increase Fitchburg's maximum daily quantity ("MDQ") under the CD-6 contract to 10.24 MMcf per day from 7.693 MMcf. The current annual volumetric limitation ("AVL") of 2800 MMcf would not change.[8]

B. Storage Return Gas

Fitchburg has storage contracts with Consolidated Gas Supply Corporation ("Consolidated") and Penn-York Energy Corporation ("Penn-York"). Since last year, and as part of the same FERC certificate application mentioned above, Tennessee has applied for authorization to transport storage return gas from Penn-York <u>on a firm basis</u> up to 2.727 MMcf per day.[9] The firm transportation would begin November 1, 1985, under proposed Rate Schedule FSST-NE. The present best-efforts transportation service of 1.239 MMcf per day would be abandoned. According to Fitchburg, Penn-York will file an application for a permanent FERC certificate to provide an annual storage volume to Fitchburg of 300 MMcf. The current FERC certificate provides for 139.9 MMcf of storage.[10] Before entering into a final transportation agreement with Tennessee, Fitchburg hopes to remove the requirement that Fitchburg use Tennessee gas to fill Penn-York storage.

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8. "Application of Tennessee Gas Pipeline Co., a Division of Tenneco, Inc. for a Certificate of Public Convenience and Necessity and Authorization to Abandon Service," Tennessee Gas Pipeline Co., FERC Docket. No. CP84-441-000; "Amendment to Application," Docket No. CP84-441-003, Exh. Z-1 at 10.
9. Tennessee has filed a Proposed "Settlement" with FERC in Docket No. CP84-441-002 which covers the proposed firm storage transportation to Fitchburg.
10. As discussed in last year's decision, 10 DOMSC 181, 191-92 (1984), FERC had approved the storage volume of 300 MMcf, but Penn-York and Fitchburg executed the storage agreement for 139 MMcf per year due to the availability of only interruptible transportation by Tennessee. Fitchburg and Penn-York have amended the agreement to provide for the full storage volume of 300 MMcf (Response No. 1 to Third Set of Information Requests).

Fitchburg's arrangement with Consolidated has not changed. Consolidated supplies Fitchburg with a maximum storage quantity of 51.35 MMcf with a maximum daily withdrawal of .468 MMcf, for which Tennessee provides transportation on a firm basis. Fitchburg is not required to take any gas from storage (Response No. 5 to Third Set of Information Requests).

C. Liquefied Natural Gas

Fitchburg's LNG contract with Bay State has not changed since last year's decision. Under the current contract, Fitchburg annually receives 250 MMcf of firm LNG, and can elect optional volumes of 75 MMcf each year through the 1987-88 heating season.

As requested in last year's decision, Fitchburg endeavors to receive the Bay State LNG by displacement transportation provided by Tennessee. Approximately 50 percent of the Bay State LNG was delivered by displacement during the 1983-84 heating season (Supplement at 19). The trucking arrangement for LNG remains unchanged, with Fitchburg receiving a maximum of 8 trucks representing 7.2 MMcf of LNG per day (Response to Information Request II.D.4).

Bay State, Tennessee, Fitchburg, and Granite State Gas Transmission, Inc. ("Granite State") signed a letter agreement to provide for delivery of a portion of the LNG by displacement during the period November 1, 1984, through March 31, 1985. Under the agreement, Bay State caused Granite State to reduce its takes of Tennessee gas at the existing Agawam Sales Meter Station in Hampden County. When operating conditions permit, Tennessee transports the gas to Fitchburg's delivery point with Tennessee. By terms of the agreement, the daily arrangements have been made on 24 hours notice. The total winter displacement volumes were limited to 150 MMcf with a maximum daily volume of 2.4 MMcf (Response No. 1 to Third Set of Information Requests). Transportation was provided on a best-efforts basis by Tennessee under FERC's emergency transportation provisions, 18 C.F.R. Part 284. Fitchburg saves 31 cents for each MMBtu delivered by displacement. Fitchburg pays a transportation charge for the 98-mile haul pursuant to Tennessee's Rate Schedule IT.

The transportation of Bay State LNG by displacement has priority over the best-efforts transportation of storage return gas because the displacement is achieved by increasing and decreasing entitlements to Tennessee gas while not exceeding the companies' total contractual entitlements (Response No. 7 to Third Set of Information Requests).

In response to information requests, Fitchburg indicated that despite new pipeline supplies, it will continue to need LNG for peak shaving needs after the 1987-88 heating season. Fitchburg anticipates extending the Bay State contract at a reduced quantity to be determined on the basis of the availability and costs of pipeline and other LNG supplies (Response to Information Request I.C.4).

According to Fitchburg a reduction in Bay State LNG volumes prior to 1988 is only possible if and when firm transportation of underground storage or an increased MDQ is approved. Given that either or both of these events may occur as early the coming summer, the Siting Council encourages Fitchburg to continue to monitor its LNG purchases and to reduce them to the extent consistent with considerations of reliability and economy.[11]

Fitchburg leases on-site LNG storage and vaporization facilities in Westminster. LNG storage capacity is limited to 4.17 MMcf, and the peak day sendout capability is 7.2 MMcf.

D. Propane

Fitchburg's plan for propane purchases has changed substantially since last year's decision. Last year, the Siting Council expressed concern about the possible renewal of long-term propane contracts after the 1984-85 heating season when short-term propane contracts might provide flexibility especially in light of the possibility of increased pipeline supplies.

Fitchburg elected not to renew its propane contracts with Petrolane-Northeast Gas Service, Inc. and C.M. Dining, Inc., which called for substantial purchases of firm and optional propane by Fitchburg through the 1984-85 heating season. Additionally, on January 22, 1985, Fitchburg completed a "buy-out" of its Petrolane contract, with a concurrent replacement of lower priced firm volumes from Gas Supply, Inc. (Responses to Information Requests I.D.1; I.D.2; Response No. 6 to Third Set of Information Requests).

Fitchburg's future plans for propane will depend on the proposed increases in pipeline supplies. For the 1985-86 heating season in particular, Fitchburg is monitoring the progress of Tennessee's application to transport Penn-York storage gas on a firm basis and the related proposals for facilities construction.

Also, Fitchburg has indicated that the contract with Bay State provides for receipt of either propane or LNG. Thus, Fithburg potentially could use the Bay State contract as a source of propane (Response No. 10 to Third Set of Information Requests).

In general, the Siting Council supports Fitchburg's action to lessen reliance on propane. Although the Siting Council has not examined closely the cost tradeoffs between firm Penn-York storage gas transportation and the use of propane, the Siting Council supports

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11. Fitchburg indicates Bay State provided a "positive response" that a reduction could be negotiated (Response to Information Request I.C.4).

generally the policy of increasing the reliability of winter supplies through firm storage gas transportation.[12]

Fitchburg owns a propane air peak shaving facility in Lunenburg with a maximum daily design capacity of 7.2 MMcf and storage capacity of 30.4 MMcf.

E. Canadian Gas

The status of Phase 2 of the "Boundary Gas" project remains uncertain. Boundary Gas, Inc., et al., FERC Docket Nos. CP81-107-000, et al. Fitchburg's projected Boundary entitlement would be 514 Mcf per day, or 188 MMcf per year. These figures are essentially unchanged since last year. But, the initial deliveries are now anticipated by Fitchburg beginning in the 1987-88 heating season (Supplement at 2).

In the early years of the anticipated ten-year contract, Fitchburg anticipates taking 75 percent of the available Boundary entitlement consistent with the 75-percent take-or-pay requirement. Later, Fitchburg would increase its takes of Boundary gas consistent with Fitchburg's growth and other supply alternatives (Response to Information Request I.E.1).

Given the uncertainty surrounding the Boundary gas project, the Siting Council encourages Fitchburg to continue to evaluate the project. Fitchburg should be prepared to justify its actions with regard to the Siting Council's standards of minimizing cost while at the same time securing a necessary and reliable energy supply.

F. Conservation Programs

A clear omission in Fitchburg's Supplement is the lack of discussion of conservation programs and their potential impact on the Company's supply planning including cost-effectiveness, although requested by the Siting Council in last year's decision. See 10 DOMSC at 195. Absent such information, the Siting Council is unable to compare (or to evaluate Fitchburg's comparison of) conservation programs to other supply alternatives.[13]

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12. Fitchburg states firm transportation of Penn-York storage gas will provide firm pipeline supplies at approximately the same cost as supplemental supplies. In the future, the transportation service will be significantly less costly if and when the transportation rates under Tennessee's Rate FSST-NE are calculated on a "rolled-in" basis with respect to the pipeline facilities required for the service (Response to Information Request I.B.3).
13. A distinction is to be made between "conservation" in the form of the observation of reduction in customer consumption, and "conservation programs" which constitute deliberate action by a gas company undertaken to hasten customer conservation or to meet requirements which would otherwise be met from conventional supply sources.

In conjunction with Fundamental Action to Conserve Energy, Inc., Fitchburg provides energy audits to residential gas customers. The audit results in a written report to the customer estimating costs and savings from low-cost energy saving techniques. Additionally, the Company provides up to $200.00 of free conservation measures to qualifying residential gas heat or water heating customers under the Louisiana First Use Tax Program (Response to Information Request CEC-1, DPU No. 84-145). Fitchburg does not have conservation programs for commercial and industrial customers, but does provide audits on request (Response to Information Request CEC-6, DPU No. 84-145).

To date, Fitchburg has not developed a specific methodology for evaluating the cost-effectiveness of conservation programs, and has performed no formal conservation studies, due to limited staff and financial limitations (Responses to Information Requests I.F.1; CEC-3, CEC-5 in DPU No. 84-145). During the Fall of 1983, Fitchburg discussed implementation of a conservation program with Citizens Energy. The Company declined to enter into the program because the Company believed reduced dependence on propane rendered the Citizens Energy proposal not cost effective to the Company and its customers (Response to Information Request CEC-5, DPU No. 84-145).

The Department of Public Utilities has ordered Fitchburg to develop specific plans for conservation and load management. Thus, Fitchburg will perform a marginal cost study with the results to be used to develop conservation and load management programs (Response to Information Request I.F.1). The Siting Council endorses the action taken by the Department and Orders Fitchburg to include in its next Supplement the results of the marginal cost study and the status of development of conservation and load management programs. Fitchburg shall specifically discuss the cost-effectiveness of conserved natural gas versus other gas supplies including a detailed justification for the method of comparison. The requirement is affixed here to as Condition One to this decision.

VI. Comparison of Resources and Requirements

A. Normal Year

In a normal year, Fitchburg must have adequate supplies to meet several types of requirements. First and most importantly, Fitchburg must meet the requirements of its firm customers. Secondly, Fitchburg must insure that its underground storage facilities are filled prior to the start of the heating season. To the extent possible, Fitchburg also supplies gas to its interruptible customers. Tables 2 and 3 display Fitchburg's projections of these requirements and the supply sources to meet these requirements in the heating and non-heating seasons for the forecast period.

1. Heating Season

In regard to the supply plan for normal heating seasons throughout the forecast period (as shown on Table 2), there have been two basic changes since last year's forecast. First, Fitchburg projects greatly

Table 2

Fitchburg Gas and Electric Light Company
Docket No.84-11A

Comparison of Resources and Requirements
Normal Heating Season
BBtu

Requirements	1984-85	1985-86	1986-87	1987-88	1988-89
Normal Firm	1596	1620	1667	1715	1762
Interruptible	50	50	50	50	50
Fuel Reimbursement	9	16	16	20	20
Total	1655	1686	1733	1785	1832
Resources					
Tennessee CD-6	1082	1056	1103	1077	1239
Consolidated Storage	51F	51F	51F	51F	51F
Penn-York Storage	139BE	307F	307F	307F	307F
Boundary				78	78
Stored LNG	4	4	4	4	4
Bay State Firm LNG	240	240	240	240	125
Stored Propane	28	28	28	28	28
Firm Propane	111				
Total	1655	1686	1733	1785	1832

Table 3

Fitchburg Gas and Electric Light Company
Docket No.84-11A
Comparison of Resources and Requirements
Normal Non-Heating Season
BBtu

Requirements	1984-85	1985-86	1986-87	1987-88	1988-89
Normal Firm SO	738	750	772	794	817
Interruptibles	500	500	500	500	500
Fuel Reimbursement				4	4
Storage Refill:					
Underground	191	358	358	358	358
Propane	28	28	28	28	28
LNG Purchases	4	4	4	4	4
Total	1461	1640	1662	1688	1711
Resources					
Tennessee CD-6	1423	1602	1624	1650	1521
Boundary					55
Firm LNG Purchases	10	10	10	10	7
Spot LPA Purchases	28	28	28	28	28
Total	1461	1640	1662	1688	1711

reduced reliance on propane, proposing to use only 28 MMcf of stored propane volumes during each heating season. Secondly, Fitchburg projects using full Penn-York storage volumes of 307 MMcf beginning in the coming heating season. In general, the Siting Council regards these changes as favorable in terms of supply reliability.

As indicated in Table 2, Fitchburg proposes to meet its normal heating season firm requirements and the small level of heating season sales to interruptible customers with its underground storage return gas, stored propane, and almost the entire firm annual contract quantities of Bay State LNG. Fitchburg plans to take less than the total available quantity of CD-6 pipeline gas from Tennessee, but also plans to use 78 MMcf from Boundary Gas beginning in the 1987-88 heating season.

The Siting Council finds that Fitchburg has sufficient supplies on a seasonal basis to meet its requirements for normal heating seasons throughout the forecast period. In particular, Fitchburg appears to have improved the reliability of its supplies through plans to upgrade Penn-York storage gas transportation, and to increase it MDQ of Tennessee CD-6 gas, while reducing dependence on propane.

However, the Siting Council has three concerns about Fitchburg's heating season supply plan. The first concern is Fitchburg's reliance on full volumes of storage gas in the course of a heating season. Aside from whether transportation is provided on an interruptible or firm basis, an issue remains whether the daily dispatch pattern in a given heating season will require use of storage gas in such a way that full storage volumes can be taken. For instance, last year the Siting Council stated, 10 DOMSC at 197:

> Fitchburg's daily sendout data for the months of November and December 1983 shows that on 28 of the 61 days during that period, Fitchburg took none of its firm Consolidated supplies. Thus, Fitchburg would need to take its full Consolidated supplies on 77 of the remaining 91 days of the 1983-84 heating season in order to receive its total available Consolidated storage volumes. The same observation applies to the Penn-York storage volumes with the added complication that transportation of these volumes is available only on a best efforts basis.

The daily sendout data for the 1984-85 heating season show that Fitchburg received Consolidated volumes on only two days during November and December 1984. Thereafter, through March 7, 1985, Fitchburg took maximum daily deliveries of Consolidated storage volumes except on two days (February 23 and 24, 1985). As of March 7, 1985, Consolidated storage volumes of 19.6 MMcf had not been taken by Fitchburg.

In regard to Penn-York volumes, the daily sendout data for the recent heating season show that as of March 7, 1985, approximately 40 MMcf had not been taken. Although the proposed upgrade of the transportation service should make this supply more reliable, Fitchburg has not demonstrated that reliance on full Penn-York storage volumes is appropriate in normal heating seasons.

The Siting Council's second concern is whether Fitchburg's projected dependence on only 28 MMcf of propane on a seasonal basis is consistent with the possible need for greater amounts of propane for cold snap requirements. Although reduced reliance on costly propane is important, the Company's current filing does not demonstrate that the reduction should be of such a magnitude in the absence of a thorough cold snap analysis.

The third concern is Fitchburg's plans for utilization of Tennessee CD-6 volumes. Last year, the Siting Council addressed Fitchburg's plans to take less than the available CD-6 gas from Tennessee, 10 DOMSC at 197 n. 26.[14] Again, Fitchburg is proposing to take less than the available CD-6 volumes during the heating seasons. This observation is particularly pertinent in heating seasons beginning in 1986-87 when the MDQ will rise to 8.8 MMcf, and to 10.246 MMcf a year later. Essentially, Fitchburg plans to take its firm Bay State LNG, as well as full Penn-York storage volumes in lieu of the increased CD-6 volumes.

Fitchburg's "predominant driving force" for increasing the MDQ to 10.246 MMcf was to increase the contribution of Tennessee CD-6 gas to a minimum of 50 percent of peak day sendout (Response to Information Request I.A.5). The second reason for requesting the higher MDQ was to allow the Company to utilize better its CD-6 supplies.[15] In fact, Fitchburg states that the new MDQ of 10.246 MMcf would enable Fitchburg to utilize an additional 386 MMcf of CD-6 gas during the winter period.[16] However, Fitchburg does not appear to project taking full advantage of the increased MDQ. Indeed, only beginning in the 1988-89 heating season does Fitchburg project a significant utilization of the proposed MDQ.

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14. With an MDQ of 7.686 MMcf, just higher than the daily component of the AVL of 7.671 MMcf, it is impossible under most daily dispatch scenarios for Fitchburg to take full available CD-6 supplies during the winter season. A perusal of Fitchburg's sendout for the last two heating seasons shows that on warm days in the shoulder months the total Company sendout does not reach levels of 7 MMcf. Thus full utilization of CD-6 supplies is practically impossible to achieve with the existing MDQ.
15. The current AVL is 2,800 MMcf (7.670 MMcf x 365). Using the current MDQ of 7,686 MMcf, the available heating season CD-6 supplies are 1,161 MMcf. Using an MDQ of 10.246 MMcf, the available winter CD-6 supplies become 1,547 MMcf.
16. Daily dispatch across the heating season should keep the actual figure somewhat lower. The increased MDQ will be useful on days when sendout exceeds the former MDQ, but will not be useful on warm shoulder days. Thus, Fitchburg cannot plan to send out the full MDQ on each day in the heating season. The increased MDQ, however, would allow Fitchburg to add additional firm customers with temperature-sensitive requirements.

In terms of cost minimization, the Siting Council has a concern in this area. Although the full volumes Penn-York storage gas will be reliable beginning in the coming heating season (assuming FERC approval), those supplies, are likely to be more costly on a per Mcf basis than the CD-6 supplies, due to the rate design for the first three years of the proposed FSST-NE rate for storage gas transportation. Also, Fitchburg projects using firm quantities of Bay State LNG[17] through 1987-88 when potentially less expensive CD-6 gas is available.

In regard to cost, the Siting Council supports Fitchburg's general movement toward lower-cost pipeline supplies and away from supplementals. Fitchburg's supply plan, however, would be improved by an analysis of firm sendout by degree days in recent heating seasons to serve as a tool for planning required levels of supplementals. Also, in its next filing, Fitchburg should be prepared to justify reliance on full Penn-York storage volumes beginning in the 1986-87 heating season when cheaper CD-6 supplies apparently will be available. To the extent Bay State is willing to renegotiate the LNG contract for lower volumes, Fitchburg should be prepared to discuss and justify the level selected.

The outlined concerns should be addressed by the Company through an analysis of sendout data during recent heating seasons adjusted for known changes in sendout requirements and supply. Specifically, the Siting Council believes submission by Fitchburg of a sendout dispatch curve referencing degree days and total sendout with the various components of supply would aid the Council in its review function.[18] This information should be accompanied by a discussion of the reliability and cost-effectiveness of using both full storage volumes in the supply plan, and the projected levels of Tennessee CD-6 volumes. This requirement is attached hereto as Condition Two.

2. Non-Heating Season

In the non-heating season, as shown on Table 3, Fitchburg plans to meet its firm requirements, refill underground storage, and make sales to interruptible customers by using its CD-6 pipeline supplies from Tennessee, a small amount of LNG, and supplies of Boundary gas beginning in 1988.

The major change since last year's filing is the larger projected storage refill requirement due to the proposed firm transportation of

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17. As discussed above, Fitchburg may be able to reduce its firm LNG purchases from Bay State. Fitchburg acknowledges it performed "no formal studies" in deriving the proposed MDQ of 10.256 MMcf, and that it does not have a firm estimate on the impact of that MDQ on purchased gas costs. More specifically, the Siting Council has not studied the impact of the increased MDQ on the CD-6 demand charges from Tennessee.
18. Fitchburg already plots sendout by degree days to determine base load and heating load.

Penn-York storage volumes. If Fitchburg sends out the CD-6 volumes as projected, the AVL of 2800 will be almost matched by the end of the forecast period. If Fitchburg is able to dispatch more CD-6 gas in the heating season the Company sendout out might match the AVL earlier.

The Siting Council concludes that Fitchburg has sufficient supplies on a seasonal basis to meet its requirements in a normal non-heating season.

B. Design Heating and Non-Heating Season

During a design year, Fitchburg must have sufficient gas supplies to meet the sendout requirements of its temperature sensitive customers, above normal year requirements. Table 4 displays Fitchburg's requirements and available supplies in a design year heating season.

Beginning in the 1985-86 heating season, Fitchburg plans to use additional Tennessee CD-6 supplies to meet requirements in a design season above those required in a normal season. Presumably, Fitchburg could utilize optional Bay State LNG through the 1987-88 heating season, as well as additional quantities of propane, in addition to the supplies shown on Table 4.

As discussed in the section on normal heating seasons, the adequacy of supplies depends on daily sendout developments over the course of the entire heating season. As indicated earlier, the total quantity of storage return gas may not be available due to the fact that storage gas not received in the early part of the heating season may be unavailable due to daily transportation limits in the rest of the heating season. Similarly, the use of supplementals is dictated largely by the weather and the daily dispatch pattern throughout the heating season. Indeed, a review of the supply plan for a design winter must go hand-in-hand with an analysis of the cold snap plan.

Table 4 indicates that Fitchburg has sufficient supplies to meet requirements in a design year <u>on a seasonal basis</u>. The Siting Council, however, believes Fitchburg's supply plan for design heating seasons would be enhanced by the analysis requested in Condition Two, <u>supra</u>, as well as the cold snap analysis requested, <u>infra</u>.

In a design non-heating season, Fitchburg does not expect its requirements to exceed those in a normal non-heating season. Fitchburg anticipates the identical firm sendout, sales to interruptible customers and storage refill requirements as in a normal year. Fitchburg has Tennessee CD-6 pipeline supplies, stored supplemental supplies, and Boundary Gas supplies (beginning in 1988) available beyond its normal resources to meet any unanticipated sendout requirements in a design non-heating season. If required, Fitchburg can reduce its interruptible sales until its underground storage is at capacity.

Table 4

Fitchburg Gas and Electric Light Company
Docket No.84-11A
Comparison of Resources and Requirements
Design Heating Season
BBtu

Requirements	1984-85	1985-86	1986-87	1987-88	1988-89
Design Firm SO	1739	1763	1810	1858	1905
Fuel Reimbursement	7	16	16	20	20
Total	1746	1779	1826	1878	1925
Resources					
Tennessee CD-6	1160	1149	1196	1170	1332
Consolidated Storage	51F	51F	51F	51F	51F
Penn-York Storage	113BE	307F	307F	307F	307F
Stored LNG	4	4	4	4	4
Bay State LNG	240	240	240	240	240
Stored Propane	28	28	28	28	28
Firm Propane	110				
Total	1746	1779	1826	1878	1925

Table 5

Fitchburg Gas and Electric Light Company
Docket No. 84-11A
Comparison of Requirements and Resources
Peak Day
BBtu

	1984-85	1985-86	1986-87	1987-88	1988-89
Resources					
Tennessee CD-6	7.8	7.8	8.8	10.8	10.8
Storage	.5	3.2	3.2	3.2	3.2
Propane	7.2	7.2	7.2	7.2	7.2
LNG Vaporization	7.2	7.2	7.2	7.2	7.2
Boundary				.5	.5
Total	22.7	25.5	25.5	28.4	28.4
Requirements	19.9	20.1	20.5	20.9	21.3

C. Peak Day and Cold Snap

Fitchburg must have adequate sendout capacity to meet the requirements of its firm customers on a peak day and in the event of a cold snap. Table 5 displays Fitchburg's peak day sendout capability, and indicates that Fitchburg's capability is adequate under normal facility operating conditions. With propane storage at one-quarter capacity (7 MMcf) and storage of LNG at capacity (4 MMcf), Fitchburg can meet projected peak day sendout requirements with these two supplemental supplies and firm pipeline supplies. See discussion at 10 DOMSC 181, 200 (1984).

Last year, in discussing Fitchburg's available supplies during a cold snap,[19] the Siting Council noted the Company's reliance on trucking of supplementals. Two projected changes will serve to alleviate partially the dependence on trucking of supplementals - the anticipated increases in the Tennessee CD-6 MDQ, and the firm transportation of Penn-York storage volumes. Also, firm Boundary volumes of 500 Mcf per day (shown in Table 5 as delayed one year until the 1987-88 heating season) would serve to alleviate partially the dependence on trucking.

Assuming full storage quantities and no replenishment of LNG or propane, Fitchburg could meet firm peak day requirements in the coming heating season for only three or four days. This conclusion assumes firm transportation of Penn-York storage gas.

To meet a prolonged period of peak day requirements of 20.1 MMcf (the projected peak day requirements next winter), Fitchburg must send out daily a total of 9.1 MMcf of LNG and propane. Under the current Bay State contract, Fitchburg can receive daily eight trucks of LNG representing 7.2 MMcf. Assuming such deliveries and send out of 2 MMcf per day of propane Fitchburg could meet a two-week succession of peak day requirements.

A thorough cold-snap analysis is a missing link in Fitchburg's supply plan. While it appears that Fitchburg has sufficient supplies to meet cold snap requirements at peak day levels from several days to as long as two weeks (assuming adequate trucking, stored levels of supplementals, and operation of facilities), this analysis does not reflect realistic weather conditions during a cold-snap and does not constitute an appropriate basis for supply planning.

Given the importance of projecting cold snap requirements and supplies, the Council will require Fitchburg to submit a cold snap

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19. The Siting Council has defined a cold snap as a number of days in succession during the heating season at or near design conditions. In order to meet cold snap requirements, a gas company must maintain high rates of sendout over an extended period by supplementing its pipeline supplies with LNG and propane. Thus, a gas company must store or have access to sufficient quantities of supplemental supplies. 10 DOMSC at 201.

analysis in its next Supplement.[20] The analysis shall reflect supply planning for a cold snap reflecting weather conditions more realistic than a series of peak days.

The analysis shall specifically indicate: the reasons for selecting the cold snap standard; the duration of the selected cold snap; the degree days projected to be experienced; and the role of supplemental supplies, including trucking and levels of storage and storage replenishment. This requirement constitutes Condition Three to be met in the next Supplement.

VII. Order

The Siting Council APPROVES the Third Supplement to the Second Long-Range Forecast of Fitchburg Gas and Electric Light Company's natural gas requirements and resources. As CONDITIONS to this approval, Fitchburg shall be required to meet the four conditions listed below.

The Company's next Supplement is due on July 1, 1985.

1. Fitchburg shall include in its next Supplement the results of its marginal cost study and a discussion of the status of development of conservation and load management programs. The discussion shall include a comparison of the cost-effectiveness of conserved gas versus other gas supplies and a justification of the method of comparison.

2. Fitchburg shall present a detailed discussion with back-up statistical documentation justifying reliance on full storage volumes during heating seasons.

3. Fitchburg shall present a cold snap analysis reflecting realistic weather conditions which contains a discussion of the selected standard, the duration of the cold snap, the degree days in the cold snap, and the role of supplementals including trucking, storage, and operation of facilities.

4. Fitchburg shall meet with the Siting Council Staff to discuss improvements to the Company's sendout methodology.

James G. White, Jr.

James G. White, Jr.
Hearing Officer

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20. Last year the Siting Council requested Fitchburg to provide a cold snap analysis and suggested an approach which would reflect realistic weather patterns. See 10 DOMSC at 201, fn. 32,

Unanimously APPROVED by the Energy Facilities Siting Council on May 23, 1985 by those members and designees present and voting: Chairperson Sharon M. Pollard (Secretary of Energy Resources); Sarah Wald (for Paul W. Gold, Secretary of Consumer Affairs); Stephen Roop (for James S. Hoyte, Secretary of Environmental Affairs); Madeline Varitimos (Public Environmental Member).

24 May 1985
Date

Sharon M. Pollard
Chairperson

COMMONWEALTH OF MASSACHUSETTS

Energy Facilities Siting Council

In the Matter of the Petition of Massachusetts Electric Company, New England Power Company, and Yankee Atomic Electric Company for Approval of Supplement 2C to the Second Long-Range Forecast of Electric Power Needs and Resources	)	Docket No. 84-24

Final Decision

James G. White, Jr.
Hearing Officer

John Dalton
William Febiger

May 23, 1985

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The Energy Facilities Siting Council ("Siting Council") hereby APPROVES without conditions the demand forecast portion of Supplement 2C to the Second Long-Range Forecast of Electric Power Needs and Requirements as submitted jointly by the Massachusetts Electric Company, New England Power Company, and Yankee Atomic Electric Company (hereinafter "Companies" or "NEES"). As described in Section IV C in this decision, the Siting Council has reviewed NEES' supply plan for adequacy of supply and the APPROVAL of the supply plan extends to supply adequacy. The issues of cost-effectiveness of the supply plan will be considered by the Siting Council in its review of Supplement 2D which was filed by NEES on May 3, 1985.

I. Background

The Massachusetts Electric Company ("MECO") and New England Power Company ("NEP") are wholly owned subsidiaries of the New England Electric System ("NEES").

NEP is a bulk power supply company and provides generation and most of the major transmission facilities for all or NEES's retail subsidiaries. These include the Massachusetts Electric Company, the Narragansett Electric Company in Rhode Island, and Granite State Electric Company in New Hampshire. NEP also serves, at wholesale, a number of municipal and other small utility systems, plus a few large industrial customers. Another NEES subsidiary, the New England Electric Transmission Corporation ("NEET"), is responsible for building terminal facilities and part of a new transmission line in New Hampshire to tie Canadian energy resources to New England.

MECO provides retail electric service for approximately 790,000 customers in Massachusetts only. The largest retail electric company in the state, MECO has a service territory that covers most of central Massachusetts and parts of northeastern and western Massachusetts. All of MECO's bulk power needs are provided by NEP. As of July 1, 1983, MECO merged with the Manchester Electric Company, which was acquired by NEES through an exchange of stock.

Yankee Atomic Electric Company owns and operates a baseload, nuclear generating plant in Rowe, Massachusetts. It has no other operating facilities and no plans for expansion. Its output is purchased by its stockholders in proportion to their ownership. NEP owns 30 percent of the stock of Yankee Atomic Electric Company and receives 30 percent of its output.

All of the NEES Companies' are members of the New England Power Pool ("NEPOOL"). As such, the planning of their bulk generation and transmission facilities is done within the framework of an overall NEPOOL regional plan which is described in the New England Forecast Report of Capacity, Energy, Load and Transmission 1984-1999 and is filed by the Companies as part of Supplement 2C of their Second Long-Range Forecast (Volume 2). The operation of NEP and NEES facilities, once placed into service after necessary regulatory approvals are obtained, is under the control of the NEPOOL dispatch center, the New England Power Exchange.

The forecasting and power planning functions for the NEES Companies are performed by the New England Power Service Company, which provides demand forecasts for each of NEES's retail companies as well as a systemwide forecast of energy and peakloads for NEES.

As a result of the relationships between the NEES companies, the Siting Council reviews the demand forecast for MECO and the supply plan of NEP, which provides resources to MECO and the other NEES retail companies. In a comparison of resources and requirements, the Siting Council reviews the NEES system as a whole.

II. History of the Proceeding

NEES filed the Third Supplement (labelled 2C) to the Second Long-Range Forecast on May 1, 1984. NEES provided public notice of the adjudication by newspaper publication and posting of the formal Notice in the Town and City Halls in the service areas of MECO and NEP.

The Conservation Law Foundation ("CLF") and the Attorney General filed Petitions to Intervene. The focus of CLF's intervention was on the issues of load management and conservation. The Attorney General's Intervention Petition alleged NEES' inclusion of Seabrook 1 power in the supply plan did not represent a necessary power supply at the lowest possible cost. The Hearing Officer orally granted both Intervention Petitions at the Prehearing Conference on July 9, 1984. This ruling was confirmed by Procedural Order dated November 13, 1984.

The parties to this proceeding engaged in an informal discovery process. The Siting Council Staff and CLF met in three technical sessions to discuss questions previously submitted to NEES by the Staff and CLF on various demand side issues. The Companies' responses to the questions are part of the record in this proceeding, as well as the responses filed May 1, 1985, to the Staff's Final Set of Information Requests.

On April 16, 1985, the parties and the Hearing Officer reached agreement that a Tentative Decision would be prepared on the demand portion of the current Supplement, and that a review of the cost issues on the supply plan including Seabrook 1, conservation and load management would be postponed for review of the Companies' Fourth Supplement (2D) which already has been filed. This agreement reflected the consensus that issuance of a Decision on demand issues would aid NEES in preparation of future filings, while review of other issues would not be unreasonably delayed by review of the Fourth Supplement (2D) which already has been filed.

III. Analysis of the Demand Forecast

A. Overview

In 1983, total sales in NEES's three retail divisions amounted to 15,764 MWH, with a summer peak load of 3234 MW. By 1993, NEES projects its system sales to be 17,860 MWH, and peak load to reach 3631 MW.

In 1983, the MECO division accounted for 74.5 percent of NEES system sales (or 11,740 MWH), 69.5 percent of system summer peak load (or 2247 MW) and 71.5 percent of winter peak (or 2286 MW). MECO's share of system sales is expected to decline slightly to 73.5 percent by 1993. MECO's peak load is forecast to shift from winter to summer in 1990, and its share of NEES's summer peak drop to 66.6 percent by 1993.

Historical and forecasted sales trends for MECO customer classes are shown in Table 1. Sales to each of the two major residential classes -- with electric heat and without electric heat -- are predicted to decline slightly, despite average annual historical increases of 1.5 percent and 1.0 percent respectively. Annual sales to the industrial class is forecast to grow at approximately 2 percent, while commercial sales are expected to rise by 1.67 percent a year. By 1993, NEES expects MECO sales to be split relatively evenly among the residential, commercial and industrial classes.

NEES prepares a demand forecast for each of its three retail companies and then aggregates the results into a system-wide forecast of demand. For each of these individual company forecasts, NEES uses a combination of econometric, end-use and stock adjustment models to forecast sales. Residential sales are forecast using an overall end use model, in conjunction with a fuel choice submodel and appliance-specific regression analyses to provide selected saturation estimates.
NEES uses regression analysis to develop the commercial and industrial forecasts. Additionally, a new end use model is under development for purposes of forecasting commercial demand in future filings.

As an input to these models, the Companies assume a constant real price of electricity. Alternative scenarios also are used to test the sensitivity of the overall forecast to different assumptions about price.

The NEES forecast of peak load utilizes the NEPOOL model, which builds up system load from separate contributions for each residential appliance, and each major commercial and industrial sector. The present forecast reflects a trend toward improving load factors over the 1983-1993 period, both systemwide (increasing from 61.3 to 63.7) and for MECO (increasing from 62.0 to 65.9). As evidenced in Table 1, the Companies expect load shape improvements most notably to affect winter peak growth, as compared to growth in both summer peak and total energy requirements. Forecast, Volume 1 at 9.

NEES acknowledges the potential for error in its forecasts of energy and peakload requirements. Further, the Companies recognize various sources of uncertainty which potentially affect the accuracy of their forecasts. These sources include: exogenous "societal" forces, unexpected changes that cannot be predicted reliably by anyone and which are beyond the control of the Companies; exogenous "policy" changes, also difficult to predict from historical experience but whose possible effects can sometimes be modeled quantitatively in advance of their implementation; and "model" errors, uncertainties associated with the data, forecasting techniques and assumptions used by the Companies. Forecast, Volume 1, pp. 4-7.

In order to better understand and elucidate some of these uncertainties, NEES evaluates and reports on the statistical confidence associated with its estimates of different variables. Moreover, NEES examines the sensitivity of its forecast results to variations in key assumptions, such as the relative price of electricity and population or economic growth rates. While the list of variables or scenarios the Companies explore in these sensitivity analyses is not exhaustive, the Companies' efforts help to place boundaries around a reasonable range of forecast results that is useful to NEES for strategic planning purposes. Forecast, Volume 1 at 13.

Overall, NEES' approach to forecasting demand -- which incorporates quality data, innovative methodologies, and appropriate sensitivity analyses -- generally instills confidence that the Companies understand the factors which drive their customers' demand for electricity now and in the future. The forecast, as presented in the original filing and through responses to information requests, is adequately documented and reviewable by the Council staff. The Companies' continued commitment to improving their forecast methodology -- most notably evidenced in this filing in the substantial efforts to introduce end use modeling of commercial demand -- is appropriate for a utility of NEES' size.

B. Demographic and Economic Activity Projections

NEES' forecast incorporates state level projections of population, and both state and national indicators of expected economic activity. Projections of these input variables are obtained from Chase Econometrics.

The methodology for developing service area projections of dwelling units remains unchanged from what the Companies filed in EFSC 81-24. State population is allocated to the MECO service area according to historical share. Number of households is estimated based on projected average household size in Massachusetts, which is assumed to follow the forecast of national trends made by the Census Bureau. Forecast, V.1 at 17.

Table 1

MECO Sales Growth Rates and Customer Class Shares

	Compound Average Annual Percent Change		Percentage of MECO System Sales	
	1973-83	1983-93	1983	1993
Residential:				
Without Electric Heat	0.99	-0.09	29.9	26.5
With Electric Heat	1.54	-0.15	8.8	7.7
Commercial	2.25	1.67	31.4	33.1
Industrial	1.60	2.07	28.9	31.7
Street Lighting	1.17	0.08	1.0	0.9
Total System Sales	1.60	1.13	100.0	100.0
Sales for Resales	0	0	0.1	0.1
Losses and Internal	1.07	1.81	5.8	6.2
Total Energy Requirement	1.57	1.17	-	-
Peak Load:				
Summer	1.29	0.74	-	-
Winter	2.05	0.50	-	-

Source: Forecast, V.3, pp. 24-27, 42-45.

The economic indicators used in the forecast include real gross national product (GNP), real state personal income, state employment, and national and state industrial production indices. The industrial forecast incorporates input data that are disaggregated by SIC. For the commercial forecast, the regression equations are based on index variables that in turn reflect weighting of state and national economic indicators along with demographic variables. Forecast, V.1 at 61.

The Companies continue to present alternative forecast scenarios that test the sensitivity of the forecast to differing assumptions about future population and economic growth. At the urging of EFSC Staff, the Companies have for the first time presented high/low scenarios based on specified assumptions about economic indicator inputs, rather than on the class-specific energy requirements that result (in part) from such inputs. Information Response D-3. The demographic and economic growth scenarios are shown in Table 2.

C. Residential

The Companies continue to use an overall end use model that aggregates energy use for 21 residential appliances. Various approaches to estimating appliance saturation are used, reflecting the Companies' characterization of each appliance as either (1) competitive/necessity, (2) non-competitive/necessity, (3) competitive/luxury, or (4) non-competitive/luxury. Estimates of average KWH per appliance are based primarily on NEPOOL data, with additional service-area-specific factors for a number of supplemental-fuel and alternative-energy arrangements associated with electric heat and hot water.

1. Appliance Saturation

The Companies' approach to estimating appliance saturations begins with allocating 12 major types of appliances into quadrants, first grouped according to their character as a necessity or luxury, and then cross-tabled to account for fuel competition. Figure 1 identifies the four appliance groupings and the principal factors affecting appliance ownership for each group.

For non-competitive/necessity items, NEES assumes constant saturation levels over the forecast period to reflect existing service area conditions. For competitive/necessity and competitive/non-necessity items, NEES makes assumptions about future fuel competitiveness as it affects appliance penetration rates for five-year periods ending in 1975, 1980 and 1985; these assumptions are documented in a simple stock-adjustment model known as COMPAPP (Competitive Appliance Model). In the non-competitive/luxury category, projected saturations are based on regression analysis (for freezers and dishwashers), NEPOOL estimates (for microwave ovens), or direct extrapolation of past percentage changes in service area ownership (for air conditioners). Forecast, V.1, pp 23-34.

The Siting Council commends the Companies for incorporating improvements into their saturation estimates reflecting the 1982 residential appliance survey NEES conducted in its Massachusetts and

Table 2

Variation Tested for Selected Model Determinants
in MECO 1995 Forecast Scenarios

Determinant	Percentage Difference From 1995 Base Case	
	High Scenario	Low Scenario
Population	+3.7	0
Electric Heat Saturation	+6.6	-7.2
Real Gross National Product	+4.3	-5.8
Real Income	+3.2	-4.4
Employment	+2.3	-4.4
Manufacturing Index	+5.7	-3.9
Price of Electricity	-14.5	+12.7

Sources: Information Response D-3. Staff Calculations based on *Forecast*, V.1 at 39, 46, and 136 and Information Response D-1.

Figure 1
NEES Residential Demand Forecast -
Factors Affecting Appliance Ownership by Appliance Group

Necessary, non-luxury items. All primary dwelling units need one of each item. There is fuel competition.

Appliances in this category:
Water Heating
Cooking
Home Heating

The decision for ownership of an appliance is based on:

- primary heat source
- annual operating cost
- installation cost
- availability of fuel source
- geographical area

Necessary, non luxury items. All dwelling units need at least one. There is no competition. Electricity has 100% of the market.

Appliances in this category:
Refrigerator
Lighting
Televisions
Clothes Washer

Competitive luxury item. It is fuel competitive, not all homes have one, and only a percentage of those that have one will have an electric one.

Appliance in this category:
Clothes Dryer

The decision for ownership is based on the following factors.

- ownership of a clothes washer
- family size
- type of housing
- primary heat source
- operating cost

Non competitive luxury items. There is no competition from other energy sources. homes Electricity has 100% of the market.

Appliances in this category:
Dishwashers
Air Conditioners
Food Freezers
Microwave Ovens

The decision for ownership is based on:

- annual income
- annual operating cost
- family size
- type of housing
- type of primary heat system
- space availability
- structural requirements (wiring)
- age of house

Source: Forecast, V.1 at 22.

Rhode Island service territories. Survey results have enabled the Companies to: (1) reduce their reliance on NEPOOL saturation data (e.g., for refrigerators, television); (2) reflect recent service-area levels of alternative energy supplementation (e.g., solar hot water, wood stoves); and (3) reflect additional explanatory variables such as family size and housing age (e.g., for freezers, dishwashers).

The Companies' use of COMPAPP, which reflects the impact of fuel competition on future saturation levels for electric space heating, water heating, ranges and dryers, remains essentially unchanged since the Council's last review in EFSC 81-24. This submodel encompasses assumptions regarding the relative prices of competing fuels resulting from deregulation of natural gas, predictions regarding oil price changes, and the impact of ongoing and expected developments in electric utility supply planning.

Recognizing inevitable uncertainties of the future energy market, the Companies specify and analyze associated probabilities for three various electric penetration rate scenarios for space heating relative to competing fuels. A mid-level penetration rate is then identified and applied to the sum of dwelling unit additions and replacements. Saturation levels for electric water heaters, ranges and dryers are then determined, based on an assumed 100-percent penetration in electrically heated homes, and past service area penetration rates in non-electrically heated homes, adjusted to match relative changes in the rates of penetration, by fuel, for space heating.

The Companies' space heating scenarios in COMPAPP are designed to reflect three possible situations: (1) gas being the economic fuel choice over electricity; (2) gas and electricity being equally economic choices; and (3) electricity being the economic fuel choice over gas. Since the model was first reviewed in EFSC 81-24, the Companies have reevaluated and sometimes changed the penetration rate scenarios and their assumed probabilities in subsequent filings. Table 3 presents a comparison of the COMPAPP space heating scenario analysis found in the EFSC 81-24 and current filings.

After developing energy use forecasts for each competitive appliance, the Companies then assess the sensitivity of 1995 total energy requirements to identified ranges of saturation for the three competitive/necessity appliances in the MECO territory. The ranges of MECO saturation and their impacts on total energy requirements for MECO and NEES are shown in Table 4. The impacts on 1995 total energy requirements are ± 1.1 percent for the MECO territory and ± 0.7 percent for NEES.

The comparisons in Tables 3 and 4 highlight two somewhat related concerns regarding the Companies' analysis of scenarios for space heating penetration. First, the scenarios are conceived primarily in terms of competitiveness between gas and electricity, without explicit recognition of the uncertainty or variability as to the competitiveness of oil. An increase in the expected 1995 penetration (or competitiveness) of oil appears in fact to be the most dramatic change in the updated analysis, as compared to the one in EFSC 81-24. Thus,

Table 3

Competitive Appliance Model
Space Heating Fuel Choice Scenarios
Current and Previous EFSC Reviews

Gas/Electricity Competitiveness Scenario	Assumed Rates of Penetration			Probability of the Scenario's Occurrence	
	Elec	Gas	Oil	1990	1995
			(EFSC 81-24)		
Gas economic choice	.30	.60	.10	.320	.064
Equilibrium	.40	.40	.20	.340	.232
Elec. economic choice	.70	.20	.10	.340	.704
			(EFSC 84-24)		
Gas economic choice	.35	.40	.25	.025	.00125
Equilibrium	.30	.35	.35	.625	.390
Elec. economic choice	.70	.20	.10	.350	.60875

Source: Forecast, Supplement 2C, V.1, Exhibit B-3a; and Long Range Forecast 2, V.3, Appendix C.

Table 4

Forecast Sensitivity to MECO Penetration Scenarios
for Competitive Necessity Appliances

	MECO Scenario	
	Low	High
Electric Heat Penetration	38.0%	72.0%
Water Heating Saturation	22.6%	24.5%
Electric Range Saturation	52.4%	56.8%
Percent change from base case:		
MECO Total Energy Requirements	-1.1%	+1.1%
NEES Total Energy Requirements	-0.7%	+0.7%

Source: Forecast, Supplement 2C, V.1, p. 136 and Staff calculations based on Information Response D-1.

although COMPAPP includes oil in the penetration-rate portion of the analysis, more interpretation of the relationship of oil-price uncertainty to the overall competitiveness analysis is needed.

A second concern with the analysis, which was apparent in EFSC 81-24 but is more so in the current filing, is that the "equilibrium" scenario is much closer (in terms of specified penetration) to the gas-economic scenario than to the electricity-economic scenario. Thus, this intermediate scenario, although representing a point between two extremes, is much closer to one extreme than the other. The electric heat saturation level included in the forecast, however, is selected as an approximate mid-point between identified extremes. A question arises as to whether a scenario interpretation concerning fuel competitiveness could be developed that corresponds more closely to the mid-point value that actually is used in the forecast. If so, it would be useful to identify and include such a scenario in the analysis, in addition to or in place of the present equilibrium scenario.

2. Average Use per Appliance

In past reviews, the Council has expressed its concerns about the Companies' reliance on the NEPOOL model for estimates of KWH per appliance. 5 DOMSC at 108 and 7 DOMSC at 294. Since the last NEES review in 1982, the Council has ordered other utilities to review the availability of data on residential appliance connected loads and use profiles, and to demonstrate the applicability of data from the NEPOOL model. See In Re Commonwealth, 9 DOMSC 264, 309-317 (1983); In Re MMWEC, 11 DOMSC 237, 257-59 (1984); In Re EUA, 11 DOMSC 61, 76-79 (1984).

The current NEES forecast continues to be based on NEPOOL data with some adjustments for space heating and water heating usage data to account for supplemental use of non-electric energy. Forecast, v.1 at 35.

In response to Council concerns about the NEPOOL data, the Companies began a research effort incorporating conditional demand analysis in conjunction with their most recent residential survey conducted in 1982. Conditional demand analysis is an econometric technique which utilizes household survey data on appliance ownership, housing and household characteristics, together with utility billing data to estimate a model of average KWH usage.[1] The technique further enables estimation of income and price elasticities and is being

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1. Income, price and other coefficients are estimated from a series of monthly average-use cross-sectional equations which include binary variables for each major appliance. These variables take on a value of one if the customer owns the specific appliance and zero if the appliance is not owned. Thus, demand is said to be conditional with respect to the owner's appliance portfolio.

considered as a cost effective means of estimating the energy usage of specific appliances or end-use devices, as well as total household average use. See Supplement 2B to Long Range Forecast 2, v.3 at 11.

The Companies expect that work on the conditional demand analysis approach will move forward, utilizing billing data compiled since the 1982 survey and the results expected from a 1985 residential survey. Information Response D-8C. The approach is viewed by the Companies as an inexpensive alternative to end use metering for validating KWH consumption of individual appliances. Information Response D-8d. In the long run, the Companies believe that the results of conditional demand analysis may be used in conjunction with similar explanatory equations of appliance ownership to form the basis of a new econometric residential model. See Supplement 2B, v.3 at 9 and 11.

The Council strongly supports the Companies' efforts in developing a potentially effective and versatile technique for explaining variability in energy usage under specified assumptions concerning appliance ownership and housing and household characteristics and information reflected in billing records. The results of the conditional demand analysis should enable the Companies to better evaluate the reliability of the NEPOOL appliance usage data they rely upon for their forecast.

In support of their position not to undertake appliance metering in the near future, the Companies cite metering equipment costs of $1,260 to $4,120 per meter, or a metering program cost of $1.3 to $4.1 million (assuming monitoring of total load and three specific appliance loads for each of 1000 customers). The Companies further point out that technology under development by NEES and others may reduce equipment and installation costs to more reasonable levels over a period of years. Information Response D-8d. While the Council agrees that expected improvements in metering technology are an important consideration, more specific long-term programs for bringing such improvements to fruition should be presented. Then, the advantages and disadvantages of further delay in implementing metering programs could be evaluated. In addition, the Companies might hasten affordable development, demonstration and implementation of more workable techniques through increased regional cooperation within New England.

The Companies also imply that the usefulness of appliance metering for forecasting purposes presently appears limited because average KWH use for a MECO residential customer has shown only minor variation (± 1.6 percent) over the past eight years. Information Response D-4. In response, it must be noted that increased penetration of appliances (e.g., electric space heating, water heating, and new small electric appliances) masks what otherwise are significant downward trends in KWH use per household resulting from conservation (e.g., insulation, more energy-efficient appliances).

Finally, the Council notes that demand forecasting is not just a means of estimating future electricity requirements, but also a tool for testing policy options related to demand-management planning. The Companies explicitly recognize the significance of policy choices for their forecasting, making particular reference to their pursuit of policy alternatives, including conservation and load management, through NEESPLAN. Forecast, V.1, p. 5-6.

To obtain a forecast useful for elucidating and evaluating demand management opportunities, there can be no substitute for appliance-specific information on energy use -- information that is best validated through direct metering. Econometric models may provide a powerful tool for adapting validated KWH information to reflect changing circumstances over space and time. The Council nevertheless continues to believe that appliance metering data which are reasonably current and specific to New England also is important for validation purposes.

The Council encourages NEES to work with other New England utilities to sponsor the acquisition of residential appliance data reflective of current appliance usage within the region. Without NEES' cooperation or leadership in such an effort, the advantages of such a region-wide effort to collect metering data may not be available to NEES or other electric utilities in the Commonwealth. The incorporation of such data into utility forecasts (either at the company level or for NEPOOL as a whole) would enhance the reliability of forecast results and the usefulness of appliance usage data for modeling the effects of alternative demand-management options.

Still, given NEES' systematic, routine and innovative use of various scenario/sensitivity analyses as part of its forecasting and strategic planning process, the Council is satisfied that the Companies are making appropriate efforts to evaluate and account for the impacts of model uncertainty on their own system planning needs.

D. Commercial

As in the last EFSC review, the Companies' commercial forecast is based on econometric models using weighted indices of demographic, local economic, and national economic factors as explanatory variables. Seven identifiable customer categories (primarily institutional), comprising approximately 15 percent of total commercial sales, are segregated and forecast separately. The remaining 85 percent of sales is classified as general commercial and projected in aggregate. Adjustments for conservation, which is assumed to increase over time, are applied post-hoc to the results of the econometric equations, to reduce projected sales for commercial customer categories.

Although this econometrically based commercial forecast uses only a partial SIC-disaggregation of the commercial sector, the Companies continue to maintain a fully SIC-classified commercial data base.

Further, the Companies are pursuing a long term research effort to allow introduction of a supplemental end-use commercial forecasting methodology. The conceptual development of an end-use model and the compilations of floor space and BTU-per-square-foot data were first reviewed by the Council in EFSC 81-24. The Council commended the Companies' efforts and recommended a broader commercial class survey to develop better data on energy by end-use. 7 DOMSC at 298-300.

The remainder of this section discusses the Company's progress in developing an end-use commercial forecasting methodology.

1. Calibration and Testing of COMMEND

The Companies describe in this filing significant new efforts to adapt and calibrate for the NEES service territories a specific end-use model--COMMEND--developed through EPRI sponsored research.

The Companies demonstrate use of the model for analysis of commercial demand by ten building types (sectors) and five universal end uses (space heating, air conditioning, domestic hot water, lighting and miscellaneous). Two sector-specific end uses were also considered--cooking and refrigeration. The current filing includes test forecasts of 1983-1995 growth rates, along with sensitivity analyses for varying assumptions about penetration rates and energy use index (EUI) growth.

A commercial end use model has extensive data requirements. The Companies summarize the steps that are required for basic development and calibration of the model as follows:

a. Development of square feet per employee statistics for the existing commercial building stock by SIC group (sector).
b. Development of a floor space inventory for the existing commercial building stock by SIC group.
c. Derivation of BTU per square foot statistics (EUI) by end use for each SIC group for existing commercial buildings.
d. Estimation of the present market shares for the various energy sources used in the commercial sector by end use and, where possible, by SIC group.
e. Estimation of EUIs for 1995 for the existing commercial building stock as well as for commercial structures constructed after 1980.

Forecast, V.1 at 66.

Although apparently bypassed in the Companies' initial test run, COMMEND allows input of even further disaggregated local data, including sales and EUIs by energy source (in addition to sector and end-use) and floor stock by vintage (in addition to sector).

The Companies' commercial data base currently includes several elements needed to implement COMMEND. Service area employment statistics are available for 1980 by town and business type. These are used in conjunction with service area estimates of square feet per employee to derive a floor space inventory. The data base also incorporates commercial sales data that have been fully classified by 2-digit SIC code since 1979. EUI estimates are derived from a 1981 NEES study and additional work performed for NEES by XENCAP, Inc. The EUI estimates reflect actual building samples that, although limited, are "thought to be typical of the service territory." Forecast, V.3 at 10. Finally, data on fuel-share also are available, but only for four commercial subsectors and on a New-England-wide basis. Thus, the fuel-share data are recognized as the most uncertain element of the Companies' data base utilized by COMMEND.

In order to calibrate the model, the Companies used COMMEND to develop a 1980 "forecast" and compared it to 1980 sales. Then, the three major input parameters--floor space, EUI and fuel share--were adjusted based on the Companies' judgements as to relative uncertainty, by sector, for each parameter. As shown in Table 5, the unadjusted forecast for the commercial class as a whole was relatively accurate, but significant adjustments were required to reconcile the forecast and actual sales figures for individual commercial groups.

Having calibrated the initial 1980 values, the Companies estimated the determinants of change that drive the COMMEND Model. Figure 2 summarizes these principal determinants and the Companies' data sources and assumptions relating to forecasts of these determinants. The kind of information afforded by the COMMEND Model is illustrated in Tables 6 and 7. As shown in Table 6, the test run indicated higher 1983-1995 growth rates for electricity sales than for floor stock in every sector except nursing homes. Table 7 shows the relative 1983-1995 growth rates by end use, along with the resulting impact on sales mix.

The Companies conducted initial sensitivity tests for selected parameters prior to selecting the assumptions for the test run. The following parameters were tested:

1. Air conditioning penetration in existing buildings.
2. Air conditioning penetration in new buildings.
3. Growth rate in Miscellaneous EUI (relative to model default rate).
4. Discount rates (for investment in new heating systems).

The sensitivities of 1995 total commercial sales to two of the parameters -- air conditioning penetration in existing buildings (set to 0 percent except for perishables warehouses) and discount rates (set higher, favoring lower-capital-cost electricity-based system) -- were relatively low (±2 percent or less). However, resetting air conditioning penetration in new buildings from 100 percent to 0 percent (again except for perishables warehouses) reduced total 1995 commercial sales by 9 percent. Resetting the model default annual growth rate in miscellaneous EUI (about 3 or 4 percent) to 0 percent reduced total 1995 sales by 10 percent. See Forecast, V.3 at 19.

The Council appreciates the fact that the Companies have kept the Council abreast of their efforts to adapt and calibrate the COMMEND model for use in forecasting sales in the NEES service territories.

The Council recognizes that the methodology is relatively new and has been tested in only a few utility service territories. The Companies have shown good planning in gradually amassing an appropriate data base. They have made significant progress in initializing the model for their territory, and in considering the relative uncertainty of key data sources and the relative sensitivity of sales to growth

Table 5

Comparison of COMMEND Model
Backcast Results to Actual Sales

(BTU x 10^9)

Building Type	1980 Unadjusted Forecast	1980 Actual Sales
Office	.32	1.36
Restaurant	.61	.79
Retail	1.91	1.50
Food Store	1.69	1.22
Warehouse - Perishables	.96	.23
Warehouse - Non-Perishables	.36	.25
Education	.75	1.37
Hospital	1.02	.81
Nursing Home	.09	.26
Services-Large Area	.45	.56
Total	8.16	8.35

Source: Forecast, V.3 at 9.

Figure 2

Sources and Assumptions for
Key Determinants in the COMMEND Model

Determinant	Source or Assumption
1. Floor space additions	Employment Forecasts: - Chase Econometrics for services, wholesale/retail, and government - Company estimates for other sectors Square feet per employee: constant throughout forecast period
2. Fuel choice logic for new heating/ventilating systems with or without air conditioning	Model default values; except for base year heat pump saturation is 5% rather than 0% for offices, and 0% rather than 5% for warehouses and education.
3. Fuel price changes (from real 1983 levels)	Electricity: no change Oil: -1% in 1984; +1% in each year thereafter Gas: +3% in each year
4. Electric cooling penetration for new buildings and replacement systems	New bldg: - office, restaurant, retail, food, store, hospital: 100% - nursing home: 20% - education: 10% - warehouse: 0% - services/large area: 80% Existing bldg. now without cooling: - office, restaurant, retail, services/large area: 40% of remainder each year - hospital and nursing homes: 10% of remainder each year - education: 5% of remainder each year - warehouses: 0%
5. Miscellaneous uses	1% annual growth in EUI

Source: Forecast, V.3, pp. 11-16.

Table 6

COMMEND Model Estimate of
Change in Sales and Floor Stock by Commercial Sector

Subsector	Average Annual Compound Growth Rate Sales (%)	Floor Stock (%)
Office	3.22	3.09
Restaurant	4.33	3.27
Retail	2.40	1.74
Food Store	1.94	1.72
Warehouse - Perishables	2.69	1.73
Warehouse - Non-Perishables	6.70	1.78
Education	0.95	-0.80
Hospital	2.00	1.00
Nursing Home	2.89	3.05
Service/Large Area	2.32	2.02

Source: Forecast, V.3 at 17.

Table 7

COMMEND Model Estimates of
Change in Sales and Sales Mix by Commercial End Use

End Use	Average Annual Compound Growth 1983 - 1995 (%)	Sales Mix 1983 (%)	Sales Mix 1995 (%)
Heating	7.46	6	11
Cooling	2.45	21	20
Domestic Hot Water	8.68	1	2
Cooking	3.02	1	1
Refrigeration	2.01	13	12
Lighting	1.77	39	35
Misc.	2.46	19	19
Total	2.61	100	100

Source: Forecast, V.3 at 17-18.

assumptions for selected parameters. The Companies have documented these implementation efforts and initial exploratory results in a level of detail often missing in other companies' descriptions of currently used forecasting techniques.

The Council commends the Companies for equipping their new commercial forecasting model with what appears to be a reasonable start-up data base. The data requirements of a newly developed or adopted disaggregated end-use model pose significant start-up challenges, and the Companies have met these challenges aggressively in their initial test runs of COMMEND. In addition, the Companies have undertaken simultaneous efforts at improving their data base. See infra, Sec. D-2.

The Companies have had to make sizeable adjustments to calibrate COMMEND to the Companies' data base.[2] The Companies have also exercised judgement in overriding some specific default assumptions while retaining others in the initial test run. These and any further adjustments made in adapting COMMEND to serve as the basis of the commercial forecast should be comprehensively reviewed and explained when and if the model is actually adopted.

In particular, there is a noticeable and significant disparity between the results of the Companies' econometrically based forecast of MECO commercial sales (1.67 percent a year from 1983 to 1993) and the results of the test run or the COMMEND model (2.61 percent a year from 1983 to 1995). This difference in average annual growth rates for the next decade would mean a difference in a forecast of 1993 MECO commercial sales of 418,000 MWH (the difference between 4,764,000 MWH from the COMMEND model and 4,346,000 MWH from the econometric forecasts). This would be a 9.6-percent increase over the current commercial forecast for 1993, or a 3-percent increase in total MECO energy requirements.

The size of these differences merely calls attention to the need for the Companies to continue to carefully calibrate the COMMEND model to their service territories, to continue to document and justify any future incorporation of the COMMEND methodology as part of their formal forecast, and to continue to undertake appropriate sensitivity analyses of important model determinants.

The Companies should also review and evaluate in future filings any continued use of non-local data or reliance on major simplifying assumptions. For example, the Companies appear to assume constant levels of square footage per employee for each sector over the entire 1983-1995 forecast period. Prospects for realizing other potential

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2. The Companies noted that incorrect SIC classifications (in the data base or in data sources for the model) could introduce error in the calibration comparison. Forecast, V.3 at 9.

strengths of COMMEND, including the ability to simulate interfuel substitutions and the ability to incorporate changes in engineering efficiencies, also should be reviewed.

2. Data Base Development

Beginning in 1983, a research project designed to expand the commercial energy end-use database was begun under contract between the Companies and XENERGY, Inc. More recently, the Companies also began to incorporate into their data base 1983 employment figures by 4-digit SIC code, as newly available for towns in the NEES service area.

The ongoing work by XENERGY, Inc. includes two principal elements -- (1) data base design for utilization of commercial audit information, and (2) analysis of billing histories. Database software has been designed and implemented to permit storage and analysis of audit and survey information. Subsequently, the Companies have completed and incorporated into the data base about 40 percent of 200 audits from a load management experiment in Gloucester, and 40 percent of 500 "low-cost" commercial industrial audits offered as part of the Narragansett Plan in Rhode Island.

With respect to billing history research, an approach for estimating building size and end-use assignments based on rate, weather, location and SIC code information has been developed. Applying the approach to a 10,000-customer random sample tested against 105 customers' bills with known end-uses, it was possible for NEES to predict the absence or presence of electric heating in 95 percent of the cases and cooling in 89 percent of the cases. Information Response D-7.

The Companies are strongly commended for their overall work in developing a commercial energy end-use data base. With regard to the MECO portion of the service area, however, one concern is the concentration of audit work in a single community --Gloucester-- that may not be that representative of the service area.[3] Prospective audit data from the state-mandated Commercial Conservation Service Program, along with the flexibility to accommodate data collected by other utilities (See Forecast, Supplement 2B, V.3 at 22), will of course offset limitations in existing MECO data. The Council directs the

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3. Unique locational and land availability factors relevant to commercial and other development are present in Gloucester (e.g., peninsula location, ledge conditions), in contrast to those in other parts of MECO's territory (e.g., prime economic development areas along Route 495 extending from the Merrimac Valley to the high growth transportation corridors between Boston and Worcester, and Boston and Providence). As a result, there may be significant differences between Gloucester and the overall MECO territory with respect to subsector composition (i.e., below the level of SIC disaggregation used in Company Forecast data), building vintage, weather, or other factors relevant to electricity usage.

Companies to discuss in their next filing the applicability of the Gloucester audits for the overall MECO territory, and the Companies' progress and plans concerning more geographically representative audit programs in Massachusetts.

E. Industrial

The industrial forecast methodology is based on econometric modeling for 2-digit and some 3-digit SIC codes. Explanatory variables reflect both national and state economic indicators. Price of electricity is also reflected, but has been held constant in real terms for forecasting purposes. The Companies present high and low system growth scenarios that reflect a range of price changes, along with ranges of economic growth and population growth.

Since the last EFSC review, the industrial forecast has been modified to address certain 3-digit SIC groups. The MECO forecast now reflects separate regression equations for the following categories:

281 Industrial Inorganic Chemicals
307 Misc. Plastics Production
357 Office, Computing and Accounting Machines
366 Electronic Communicators
367 Electronic Components

As justification for disaggregation at the 3-digit level, the Companies cite significant regional-national differences (and service area differences) in KWH per dollar of value added at the 2-digit level.[4] The Companies believe compositional differences apparent at the 3-digit level can account for much of the inter-regional variation in energy intensiveness. Forecast, V.1 at 84-85.

At the same time that the Companies were successfully introducing more disaggregated forecasting for some sectors, their ability to maintain regression-based forecasts in other sectors evidently was diminishing. The number of 2-digit SIC categories that the Companies did not successfully model at either the 2- or 3-digit level increased from three in EFSC 81-24 (i.e., for SIC's 22,34,37) to six in the current filing (i.e., for SIC's 22,25,26,27,34,37).[5] The successful use

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4. For example, KWH per dollar of value added for SIC 26 (paper and allied products) in the U.S., Massachusetts and Rhode Island were 4.508, 2.057, and 1.522 respectively in 1975. Forecast, V.1 at 84.
5. The Companies state that, where no explanatory relationships were found, SIC-group forecasts were made by assuming a relationship between KWH and industrial value added. Forecast, V.1 at 92. For the six SIC categories so forecast in the current filing, MECO projected sales amount to 793 GWH, or 24.9 percent of MECO projected total industrial sales, in 1985. Forecast, V1 at 101. For the three SIC categories so forecast in EFSC 81-24, MECO projected sales were 506 GHW, or 15.2 percent of MECO projected total industrial sales, in 1985. Second Long-Range Forecast, V.1 at II-104.

of price of electricity as an explanatory variable in SIC-group forecasts also dropped from four cases in EFSC 81-24 to one case (SIC 29) in the current filing.[6] For all but two cases (SIC 20,29) of 15 regression equations in the current filing, only single independent variables (driving variables) are used to determine the respective SIC-group forecasts. Forecast, V.1 at 97.

Where there is no explicit consideration of price in the regression-based forecasting of industrial sales, the Companies use separate estimates of price elasticity by SIC to consider possible effects of real price changes on sales. The elasticity estimates do not affect the current forecast, which assumes a constant real price of electricity. However, high and low price scenarios were developed and the impacts on total sales analyzed using the elasticity estimates. Forecast, V.1 at 92. The elasticity estimates are derived from a 1980 study by National Economics Research Associates (NERA), reviewed by the NEPOOL Load Forecasting Task Force. Information Response D-9.

The Companies recognize that some industrial groups, especially the more energy intensive groups, may cope with any expected increases in energy costs by modifying the production process. The forecast continues to include a conceptual "production function" framework, developed in response to previous EFSC concerns about the need to address the relationship between price and industrial conservation. 5 DOMSC at 115-116. The framework recognizes three distinct forms of possible price impact on the production function:

1. efficiency - the use of less energy to achieve the same level of productive output;

2. substitution - the use of different fuels to produce the same level of productive output with the same amount of energy; and

3. mix - the use of less energy by changing the level of productive output.

As yet, the Companies have not presented a methodology for quantitatively distinguishing the relative importance of the three forms of price impact by sector. In the present review, the Companies state that further development of the production framework has been abandoned, as they believe that the mix of industries in their service territory continues to shift away from electricity-intensive manufacturing processes that are well modeled by a production function framework. Information Response D-8d.

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6. Even in cases where it has been retained, real price of electricity generally has shown t-statistics with absolute values of less than two -- an indication that the explanatory value of the variable is questionable. See Forecast, V.1 at 97, Second Long-Range Forecast, Supplement 2A, V.1 at II-98, and Second Long Range Forecast, Supplement 2B, V.1 at 104.

The Council supports the Companies' work in developing SIC-group forecasts at the 3-digit level. The five SIC-groups forecast at this level, accounting for 37.7 percent of total MECO industrial sales in 1983, were appropriately chosen based on relative size. Information Response D-8a. The expected 1995 sales for the sectors in which 3-digit forecasting was introduced amount to 2326 GWH, or 52.2 percent of projected 1995 total industrial sales.

However, the Companies acknowledge a major block to developing further detail on a 3- or 4-digit SIC basis is the limited availability of forecasts of explanatory macroeconomic variables. Selected forecasts at the 3-digit level are available from Chase Econometrics, on a national basis only. The Companies have been unable to locate detailed industrial forecasts on either a national or regional basis from other consulting firms. Information Response D-8a.

The Council accepts these difficulties as constraints on the Companies' ability to further disaggregate the industrial forecast. So, the Council's principal concern with the industrial forecast is the Companies' limited attention to the relationship between energy costs and the production function.

Given the ongoing commitment of resources to improving the commercial forecast methodology, the Companies' position not to invest also in immediate and intensive development of a "production function" approach to industrial forecasting is somewhat understandable.

However, industrial sales are expected to increase faster than those to any other sector. NEES expects them to account for an increasingly large percentage of system sales through 1993 -- and in fact to be comparable in volume to commercial sales that year. In recognition of the importance of activity in this sector, the Council encourages NEES not to forego further model and data development in the industrial-sector forecast.

Further, the Companies' current forecast mutes somewhat the issue of electricity prices by assuming that they will remain constant. As noted above, high-and low-price scenarios are analyzed based on NERA elasticity factors.

An expectation of constant price does not remove the theoretical ability of the price variable to more accurately account for base period trends in electricity usage which do reflect price changes. NERA elasticity factors, although perhaps acceptable for a sensitivity analysis, would provide a questionable basis for the Companies' industrial forecast itself should changing real prices of electricity again become a factor to be incorporated in future forecast filings.

In the absence of a concerted effort to model energy costs as a factor of production, the Council therefore believes that the Companies should undertake some review in the near term of the role of price in their industrial forecast.

F. Internal Use and Losses

The Companies forecast MECO internal use and losses to increase from 681 MWH in 1983 to 815 MWH in 1993. As shown in Table 1, the compound average annual increase is 1.81 percent -- significantly higher than the historical average annual increase in internal use and losses (1.07 percent) as well as the forecast average annual increase in MECO system sales (1.13 percent).

The relatively high projected increase in internal use and losses is at odds with the Companies' observations in the Forecast as to a long term downward trends in this category. Forecast, V.1 at 105. The Companies' acknowledge the inconsistency, noting that the equation underlying the forecast of internal use and losses has not been reestimated since 1981. It is agreed that the inconsistency will be addressed in future filings. Information Response D-9.

G. Conclusions: Demand Analysis

The NEES Companies' demand forecast and forecasting methodologies continue to exhibit steady, evolutionary development of the highest standards. The demand forecast of a compound average annual growth of 1.7 percent for the commercial sector and 2.1 percent for the industrial sector, an average annual decrease of 0.1 percent for the residential sector, and an overall annual growth rate of 1.2 percent in electric energy consumption and the attendant forecasting methodologies are hereby APPROVED without conditions.

The Council encourages the Companies to continue to refine their forecast capabilities and data collection methods. In particular, the Council encourages the Companies to:

- Update the fuel choice analysis in the residential Competitive Appliance Model to more explicitly reflect uncertainty as to competitiveness of oil, and to more explicitly interpret gas-electricity competitiveness in the fuel choice scenario (i.e.,penetration rates) actually selected as the basis of the forecast;
- work with other New England utilities to sponsor the acquisition of residential appliance data reflective of current appliance usage within the region;
- continue to carefully calibrate the commercial end use (COMMEND) model to the MECO service territory, to assess input data reliability and forecast sensitivity for key model determinants, and to document and justify any incorporation of COMMEND as part of the formal forecast; and
- review the role of electricity prices in the industrial forecast, and consider further model and data development to reflect energy costs as a factor of production.

IV. Analysis of the Supply Plan

NEES' bulk power supply is provided by NEP, its wholesale power supply operating subsidiary. NEP also serves a number of small municipal and investor-owned utility systems and exchanges power with other New England electric utilities as part of the New England Power Pool (NEPOOL). In its role as NEES's bulk power supplier, NEP provides the generation and most of the major transmission facilities for the NEES retail Companies: Massachusetts Electric Company, Narragansett Electric Company, and Granite State Electric Company.

NEP owns 4,267.4 MW of generation capacity,[7] 386.1 MW of which are under short-term capacity sale agreements.[8] An additional 239.6 MW of capacity are available to NEP under capacity purchase contracts with other electric utilities and small power producers (SPP),[9] giving NEP a total net generating capacity of 4,122.3 MW.[10] Coal-fired units account for 35 percent of this net capacity; oil-fired units for 28 percent; pumped storage and conventional hydro units for 26 percent; diesel oil peaking units for 1 percent; and SPPs for less than one-half percent (See Table 8).

NEES projects a total available system capacity of 4,855 MW by the close of the forecast period (December 1993), representing a net increase of 733 MW.[11] Of this increase, NEP's entitlements in two nuclear projects currently under construction - Seabrook 1 (114.5 MW) and Millstone 3 (139.5 MW) - account for 255 MW. Small power production accounts for an additional 135 MW. The remaining increment of 343 MW results from the expiration of all but three capacity sales agreements, a total of 15 MW, and one capacity purchase agreement of 27.7 MW.

The Siting Council uses three criteria - adequacy, diversity, and cost - to evaluate a company's supply plan. The evaluation of adequacy is based on a company's ability to meet its forecasted peak loads and

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7. Unless otherwise noted all data in this section are as of May 1, 1984, the Forecast submission date. Included in this capacity figure is NEP's 30-percent share of the Mass Yankee plant, owned and operated by the Yankee Atomic Electric Company, of which NEP is a stockholder.
8. Included in this capacity sale figure are 15 MW of unreserved system capacity sales to the Hudson Light and Power Department. Response to Information Request CT-1.
9. Included in this figure are the 15.3 MW from Lawrence Hydroelectric.
10. Response to Information Request CT-1.
11. Response to Information Request CT-1.

Table 8

NEP
Net Generating Capacity

	Actual (5/1/1984)		Forecast (12/31/1993)	
	MW	% Of Total	MW	% of Total
Nuclear	387.0	9.4	641.8	13.2
Coal	1,429.7	34.6	1,506.3	31.0
Petroleum	1,172.5	28.3	1,324.5	27.2
Diesel	56.0	1.4	56.0	1.2
Pumped Hydro	484.0	11.7	584.0	12.0
Conventional Hydro	592.6	14.3	592.6	12.2
Small Power Production[1]	15.3	0.4	150.0	3.1
Total[2]	4,137.1[3]	100.1	4,855.2	99.9

Source: NEP Capability Position Report, dated September 27, 1983, Response to Information Request CT-1.

1. The 15.3 MW of Small Power Production (SPP) are accounted for by Lawrence Hydroelectric. The 150 MW for 1993 are projected. (See Section IV.B.4. Infra.)
2. Totals do not add to 100% due to rounding errors.
3. Actual net capacity available is 4,122.3 MW as a result of sale of unreserved capacity (15 MW) to the Hudson Light & Power Department.

reserve requirements under forecasted "best guess" conditions and under reasonable contingency test criteria appropriate to the company. The cost and diversity evaluations focus on a company's current supply mix and the major programs being pursued to minimize costs and enhance diversity.

The parties in this case agreed to limit the scope of the supply side review to a primarily descriptive discussion of the Companies' supply plan. All parties agreed that it would be duplicative to adjudicate the Companies' Seabrook 1 investment in this forum, since this subject had received an extensive review by the Massachusetts Department of Public Utilities ("DPU"). See Section IV.B.2, infra. Furthermore, since the Companies were soon to file a new forecast supplement and release an update on the Companies' supply planning activities, both of which would significantly change the Companies' supply plan, the parties agreed that this review should be primarily descriptive and that the Council's findings would be limited to the one area which would not be significantly affected by these changes - the adequacy of the Companies' supply. Further, it was agreed that a formal review of the cost and diversity of the Companies' supply would be conducted in the next NEES forecast review with the benefit of this new information.

A. Adequacy of Supply

Table 9 provides a comparison of NEP's projected net capacity, peak demand and reserve requirement for each summer of the forecast period.[12] NEP shows a capacity surplus over its projected capability responsibility throughout the forecast period.[13] This annual surplus falls within a range of 6.7 percent of capacity over requirements (summer of 1986) to 14.1 percent (summer of 1985).

Assuming the Companies' projected annual load growth of 1.5 percent, NEP would be able to meet NEES's capability responsibilities through 1993 with existing generating units, under current capacity purchase and sale agreements.[14] The Companies have sufficient net capacity available to meet their capability responsibility without capacity from either Seabrook 1 or Millstone 3, or both units, during the forecast period. Therefore, construction schedule slippages, or even outright cancellation of both of these units, would not create a capacity shortfall for NEES through 1993.

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12. NEES forecasts that its system will experience a summer peak throughout the forecast period.
13. The Council has not formally evaluated NEP's capability responsibility in this review. Therefore, reserve requirements - 15 percent of the system's peak through 1987 and 21 percent beyond - are based on the range of reserve requirements provided in the Forecast. Forecast, Vol.2, p.31.
14. See Table 9. This is systemwide load growth.

Table 9

NEES's Projected Summer Net Capacity, Peak Demand, and Reserve Requirement from 1984-1993
(MW)

		Summer 1984	Summer 1985	Summer 1986	Summer 1987	Summer 1988	Summer 1989	Summer 1990	Summer 1991	Summer 1992	Summer 1993
a.	Existing Facilities (12/31/83)	4,240.3	4,240.3	4,240.3	4,240.3	4,240.3	4,240.3	4,240.3	4,240.3	4,240.3	4,240.3
b.	Unit Purchases	224.3	224.3	196.6	196.6	196.6	196.6	196.6	196.6	196.6	196.6
c.	Unit Sales	371.1	275	373	140	120	120	120	15	15	15
d.	Small Power Production[1]	15.3	15.3	25	55	55	55	90	90	120	120
e.	Total (a + b + c + d)	4,108.8	4,205.0	4,089	4,352.0	4,372.0	4,372.0	4,407.0	4,512.0	4,541.9	4,541.9
f.	Capacity Purchases (Sales)	(15)	(14)	(5)	-	-	-	-	-	-	-
g.	Planned Units[3]	-	-	140	140	255	255	255	255	255	255
h.	Net Capacity (e + f + g)	4,094	4,191	4,224.0	4,492	4,627	4,627	4,662	4,767	4,797	4,797
i.	Projected Peak Load	3,144	3,194	3,273	3,324	3,374	3,426	3,476	3,529	3,579	3,631
j.	NEPOOL Reserve (15% thru 1987 21% beyond)[2]	472	479	687	698	709	719	730	741	752	763
k.	Capability Responsibility (i + j)	3,616	3,673	3,960	4,022	4,083	4,145	4,206	4,270	4,331	4,394
l.	Excess (Deficit) Capacity (h- k)	478	518	264	470	544	482	456	497	466	403
m.	% Excess (Deficit) (l ÷ k)	13.2%	14.1%	6.7%	11.7%	13.3%	11.6%	11.1%	11.6%	10.8%	9.2%

Source: Response to Information Request CT-1.

1. Lawrence Hydroelectric included under Small Power Production rather than under Unit Purchases as it is accounted for in the Forecast, Table E-12.
2. Assumed Reserve Requirements based on information presented in the Forecast, Vol. 2, p.31.
3. Seabrook I assumed to come on line 11/87. Response to Information Request SMP-1b.

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1. Contingency Planning

Contingency planning is a formal part of the Companies' supply planning process.[15] This helps to ensure that NEP has sufficient capacity throughout the forecast period even if demand grows at a faster than expected rate and/or if planned capacity additions are delayed or cancelled.

Inherent in any long-range demand forecast or supply plan are major uncertainties pertaining to the accuracy of these "best estimates." Contingency planning is a way to evaluate the costs of these uncertainties to determine whether additional action should be taken to minimize the risks of forecasting error and the loss of supply options.

In its Second NEESPLAN Update, NEES uses two contingency criteria "to demonstrate the Company's flexibility to cope with the occurrence of unpredictable events."[16]

> The first contingency is a 50 percent increase in projected annual load growth, resulting in a compound growth rate of 2.75 percent per year. The second is a reduction in generating capacity by 500 MW from that planned for the next 15 years.[17]

These contingency criteria enable the Companies to explore the effects of unexpected conditions on their ability to met their capability responsibility. For example, the effect of the second contingency approximates what would occur if Seabrook 1, Millstone 3, and all projected small power production were not available at the end of the forecast period. Even under these stringent contingency conditions, NEP would be able to meet its capability responsibilities throughout the forecast, as long as the Companies' load management implementation schedule is accelerated.

NEES has identified two other strategies besides accelerating the load management implementation schedule that further bolster the adequacy of its supply: 1) peaking units could be constructed; and 2) capacity entitlements could be secured from Canada.[18] Any or all of these strategies could be implemented to ensure that customers' needs are met.

The Council commends NEES for using contingency planning as part of its supply planning process. Further, the Council urges the Companies to retain the contingency planning process as part of their supply planning and to formalize their contingency test criteria (e.g., 50 percent increase over forecasted load growth) to ensure that contingency

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15. Both the first and second NEESPLAN updates have specific chapters dedicated to reviewing the Companies' contingency planning efforts.
16. Response to Information Request CP-2.
17. NEESPLAN, C.VII, p.6.
18. Forecast, Vol. 2, p.32.

planning is used by the Companies to ensure an adequate supply under a reasonable set of unexpected conditions.[19]

The Council recognizes that contingency test criteria must be balanced in terms of the cost of satisfying the criteria (e.g., securing back-up or additional capacity) and the benefits from the reduced risk of a "supply shortfall." Given this need for balance, the actual risk level used in the contingency criteria is likely to change as the Companies' supply and demand outlook changes. However, the procedure for determining the appropriate contingency test criteria should remain the same.

Therefore, based on the Companies' current capacity surplus, plans for capacity additions, and contingency planning efforts, the Council finds that the Companies' supply plan provides an adequate supply of power throughout the forecast period even under severe contingency conditions.

B. Cost and Diversity of Supply

In accord with the agreement made by all parties in this proceeding, in this decision the Council will make no judgements on the cost and diversity of the Companies' supply. A formal analysis and full evaluation of the cost and diversity of the Companies' supply plan will be performed in the next NEES forecast review.

The primary objectives of the Companies' supply planning efforts, as outlined in the NEESPLAN Second Update, are to: 1) "[r]educe foreign oil use from 74 percent to 10 percent of our energy needs, and 2) keep our customers' energy costs to a minimum consistent with reliable electric service."[20]

These two objectives are interrelated. NEP's efforts to diversify its generating mix have also served its cost minimization objective. Prior to 1979 all of NEP's coal-fired capacity summarized in Table 8 burned oil; and these oil-fired units provided 74 percent of the Companies' energy requirements.[21] By 1983, however, with its coal conversion program well underway, NEP's oil-fired units provided only 20

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19. Contingency planning can be used to ensure adequate supply in the following way: If, under the circumstances defined in a formalized contingency test criteria, NEP would not expect to be able to meet its capability responsibilities with resources included in its existing supply plan, then the Company should identify a supply option (or options) which could be relied upon with a reasonable degree of certainty and in a sufficient time frame in the event that the contingency occurred.
20. NEESPLAN, C.I, p.2. NEESPLAN outlines the Companies' supply planning initiatives.
21. NEESPLAN, C.III, p.3.

percent of the Companies' energy requirements.[22] See Table 10. NEES reports that in 1982 alone, these coal conversions saved its customers approximately $45 million in reduced fuel costs.[23]

The companies have identified four strategies to further balance their fuel mix and to "keep ... customers' energy costs to a minimum:" 1) Canadian hydro energy imports by NEPOOL; 2) the completion of the Seabrook 1 and Millstone 3 nuclear units; 3) conservation and load management (CLM); and 4) contracts with small power producers.[24] Although the Siting Council has reached no conclusions as to the cost-effectiveness of these options, each of these strategies is described below.

1. Canadian Hydro

NEPOOL representatives have signed two agreements - Phase I and Phase II - with Hydro-Quebec which provide for the exchange of power between the two systems.[25] Given that "NEPEX will dispatch the Canadian energy to displace the most expensive oil and produce the greatest savings,"[26] the Phase I & II agreements appear to offer NEES customers two major benefits - lower fuel costs and enhanced supply diversity.

Under Phase I, Hydro-Quebec will use best efforts to provide 33 billion KWH of surplus energy for an eleven year period beginning in September 1986; a five year extension is allowed if the 33 billion KWH goal is not met. This surplus energy will be priced at roughly 80 percent of NEPOOL's average fossil fuel cost for the previous year. The actual pricing formula will depend on whether the power is prescheduled. The Phase I contract provides for the scheduling of two-thirds of all energy sales, yet delivery is not guaranteed. NEPOOL has determined that the Phase I agreement will reduce the pool's need for new capacity by 600 MW.[27]

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22. By December of 1983, NEP's Brayton Point coal-capable units - Units 1 thru 3 - and Mt. Tom, of which it owns 56 MW, were fully converted to coal; the Salem Harbor coal-capable units - Units 1 thru 3 - were burning coal under a Delayed Compliance Order. NEESPLAN, C.III, p.3.
23. NEESPLAN, C.IV, p.2.
24. NEESPLAN, C.III, p.12-14.
25. Discussion of the Hydro-Quebec projects is limited since one of these projects, Phase II, is being evaluated by the Siting Council in detail in another proceeding, New England Hydro-Transmission Elec. Co., et al., Docket No. 84-24(A).
26. NEESPLAN, C.III, p.5.
27. Forecast Supplement Amendment of New England Hydro-Transmission Electric Co., Docket No. 84-24(A). Updated April 12, 1985, Vol. 1, p. 10.

Table 10

NEP Energy Mix 1979-92

(thousands of MWH)

	1979		1983		1988		1992	
	MWH	% Mix	MWH	% Mix	MWH	% Mix	MWH	% Mix
Coal	121	0.7	9,576	55.1	9,636	52.3	9,636	48.4
Oil	12,879	76.7	3,523	20.3	2,638	14.3	3,574	17.9
Nuclear	2,400	14.3	2,544	14.6	3,900	21.2	4,138	20.8
Hydro	1,400	8.3	1,740	10.0	1,400	7.6	1,400	7.0
Small Power Production[1]	-	-	-	-	840	4.6	1,180	5.9
	16,800	100.0	17,383	100.0	18,414	100.0	19,928	100.0

Source: 1979 & 1983 data are from NEESPLAN Second Update, C. III, p.3; and 1988 & 1992 data are from Response to Information Request CT-7.

1. SPP incorporated in Hydro Classification in NEESPLAN.

The Phase II agreement is expected to provide an additional 7 billion KWH per year on a take-or-pay basis, beginning in 1990 for a period of 10 years.[28] Under Phase II, Hydro-Quebec reserves the right to limit energy sales for up to 200 hours per year. According to an analysis performed by NEPOOL, the Phase II agreement and the increased interconnection capability would defer the need for 900 MW of new capacity.[29]

As a member of NEPOOL, the Companies are entitled to a share of the power to be imported from Hydro-Quebec under the Phase I and II agreements. For Phase I, the share of costs and benefits is based on each participating company's percentage share of the total 1980 retail sales in New England. For the Companies, this is 18.5 percent of the project or between 550,000 to 900,000 MWH per year, depending on water conditions and Hydro-Quebec's demand growth.[30] NEES has estimated that the Phase I agreement will provide its customers with a cumulative savings of $300 million from 1987 through 1998.[31]

NEES estimates that the total present worth of the net benefits from the Phase II agreement for all NEPOOL customers will be roughly 610 million dollars ($ 1990).[32] Although the distribution formula for Phase II has not been finalized, the Companies believe their share will likely be close to their Phase I share. Assuming an 18.5 percent share of the Phase II power, the NEES entitlement would be approximately 1,300,000 MWH per year throughout the Phase II contract period.

The costs and savings from Hydro-Quebec Phases I and II will be determined on a NEPOOL-wide basis. NEES expects that NEP's share of these savings will be accounted for as part of its monthly interchange statement from NEPOOL. Given these arrangements, the Hydro-Quebec cost savings are not directly accounted for by NEES in its production cost model. When NEES evaluates different supply options, it factors in the impact of Hydro-Quebec energy on total energy costs as an "after-the-fact adjustment on the output of the [production] model."[33]

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28. The Phase II agreement is actually only an agreement in principle; the formal contract has not been signed.
29. Forecast Supplement Amendment, New England Hydro-Transmission Electric Co., Docket No. 84-24(A). Updated April 12, 1985, Vol. 1, p.10.
30. NEESPLAN, C.III, p.5.
31. NEESPLAN, C.III, p.5.
32. Forecast Supplement Amendment, New England Hydro-Transmission Electric Co., Docket No. 84-24(A). Updated April 12, 1985, Vol. 1, p.78. Included in this estimate are deferred generation equipment savings, which are not actually savings to NEES customers. Thus, the actual savings to NEES customers would be less than its pro-rated share of the total savings. Note that this total net benefits estimate for Phase II is not directly comparable to the Phase I cumulative savings estimate.
33. Response to Information Request SMP-7.

When asked by the Siting Council about "the impact of Hydro-Quebec power on system energy costs as reflected in .... the cost effectiveness of supply planning options,"[34] NEES states: "In the case of evaluating the cost-effectiveness of supply planning options, Hydro-Quebec Phases I and II would tend to reduce the System's energy costs. On the margin, this might reduce the attractiveness of certain LM&C programs."[35]

2. <u>Nuclear Entitlements</u>

NEP's entitlements to Seabrook 1 (114.5 MW) and Millstone 3 (140.4 MW) account for over one-third of the Companies' forecasted 733 MW increase in capacity over the forecast period.

NEP assumes that Seabrook 1 will begin commercial operation in October 1987.[36] New Hampshire Yankee, which is overseeing construction of the unit, estimates the incremental cost of completing Seabrook 1 to be $779 million.[37] Northeast Utilities estimates the incremental cost of completing Millstone 3 to be $559 million.[37]

NEES supports the completion of both these units on the basis of the fuel savings they offer "because these plants would displace oil-fired units."[38] NEES currently attaches no capacity value to these units, because the Companies have sufficient capacity to meet their capability responsibility throughout the forecast period.[38]

The Council draws no conclusions here about the energy or capacity value of Seabrook 1 to NEES. In fact, the Council presided over an agreement made by the parties in this case that Seabrook 1 would not be an issue in this proceeding, since the parties were involved in a proceeding at the DPU to review both the cost and in-service dates of the Unit (the "generic" review) and the Companies' plan to finance the remainder of the Seabrook investment (the financing review). The DPU had instituted the generic proceeding ---- in response to a petition from NEP, and three other electric companies ---- to open a consolidated docket to review certain aspects of the Seabrook project.[39]

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34. Information Request SMP-6.
35. Response to Information Request SMP-6ii.
36. This is the estimate used by NEP for financial planning purposes. Response to Information Request SMP-1b.
37. These are the estimates of the cash to be spent between 1/85 and commercial operation of these units, i.e., without AFUDC. Response to CLF Information Request 2.h.
38. Response to CLF Information Request 2.f.
39. Specifically, the DPU investigated the estimated completion cost of Seabrook 1, including construction and financing costs; the estimated completion and commercial on-line dates; and the estimated operating characteristics of Seabrook 1. DPU No. 84-152.

On April 4, 1985, the DPU issued a decision in the "generic" Seabrook 1 proceeding, DPU No. 84-152. The DPU concluded that the investor-owned utilities, including NEP, had failed to show requested financings were necessary, but that the utilities could attempt to proceed with financing in a manner which placed risk of continued participation in the project on shareholders.[40] The DPU also found the earliest reasonable completion date for Seabrook 1 was August 1988, with the possibility of a later date.[41] NEP and the other affected electric companies have appealed the DPU's decision to the Supreme Judicial Court.

Seabrook 2 was not included in the Companies' forecast because the joint owners have decided "to cancel Unit No. 2 if certain conditions are met."[42] Although no progress has been made in meeting these conditions and the Unit has not been formally cancelled, work on Unit 2 has stopped.

NEP was the first of the joint owners to call for the cancellation of Unit No. 2. NEP's decision to vote to cancel Unit No. 2 was made "on the basis of such factors as competing fuel prices, construction costs and customer load growth..."[43] The Council commends NEES for its leadership role in promoting the cancellation of Unit No. 2 given the considerable uncertainty regarding its cost and in-service dates. The Council urges NEES to employ the same degree of vigilance in reviewing the cost-effectiveness of Unit No. 1.

3. Conservation and Load Management Programs

NEESPLAN calls for conservation and load management (CLM) programs to be an important part of the Companies' supply plan. The Companies' near-term CLM implementation plans are limited, however, given the Companies' near term capacity surplus and their adherence to the no-losers test for program evaluation.[44]

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40. DPU No. 84-152, Order dated April 4, 1985, at 71-72.
41. DPU No. 84-152, at 48-49.
42. Forecast, Vol. 2, p.1. These conditions require, in part, that a portion of the savings from the Hydro-Quebec power purchase agreements be used to pay off the Public Service Company of New Hampshire's debt associated with Seabrook 2.
43. NEESPLAN, C.III, p.9.
44. Under the no-losers test, a CLM program would be rejected if its implementation led to revenue erosion and additional revenue requirements greater than would have occurred in the absence of the program. This standard ensures that average rates do not rise above what they would have been without the program. Where a utility's average cost of production exceeds its marginal cost of production, no company-sponsored programs can pass a no-losers test. NEES' average production costs currently exceed its marginal costs. However, NEES believes marginal costs could exceed average costs in 1985. Response to Information Request SP-1.

Presently, in portions of the NEES service territory with transmission and distribution bottlenecks, the Companies are using selective load management programs to defer needed capital investment in the transmission and distribution system. For the most part, however, the Companies' current participation in CLM programs is limited to three types of programs: 1) educational programs which are a long term investment whose return is neither easily calculated nor convertible into cost-effectiveness indices; 2) experimental programs which are used to collect data necessary for program design and evaluation; and 3) stock adjustment programs which will not be cost-justifiable once the "investment window" has passed (e.g., storage heating is generally only cost-effective during initial building construction).[45]

For the long term, the Companies' CLM programs serve two primary goals: 1) "to prepare ... for quick action in the event load growth is higher than currently forecast;" and 2) "to defer capacity additions that ... [the] current forecast shows would otherwise be needed shortly after the year 2000."[46]

Given their current load forecast and understanding of the system's load shape, the Companies' estimate that the maximum contribution from "a full scale load management" implementation program by 1998 could be approximately 350 MW below the natural peak.[47] Table 11 shows the estimated contribution by program if full scale implementation were to begin in 1989. These estimates are based on a comparison of the system's projected peak load profile with an assessment of the ability of different programs and technologies to move load off peak.[48]

NEES expects to use its experimental and data collection CLM programs eventually to ensure that the reasoned judgements on which these load reduction estimates are based are realistic. The Siting Council views such program experimentation as essential to the development of an "optimum" load management implementation schedule which takes into account the costs, peak load reductions, and implementation lead times of these programs. Therefore, the Council encourages the Companies to continue to run these valuable experimental and data collection programs due to their important contribution to the ability of the System to evaluate the full range of resources available to it for its long-run supply plan.[49]

4. Small Power Production

NEP has been successful in securing contracts with a number of small power producers (SPP). It expects to have 150 MW of SPP under

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45. Response to Information Request SP-1.
46. NEESPLAN, C.I, p.2.
47. Forecast, Vol.1, p.108.
48. Response to Information Request SP-3.

contract by the end of the forecast period,[50] and it is well on its way to meeting this target. Currently 23.1 MW of SPP are under contract and in operation, and 90 MW are under contract and under construction and are anticipated to be in service by the end of 1985.[51] See Table 11. In addition, NEP is provided with energy under PURPA or filed auxillary service rates by a number of SPPs: 0.3 MW from 52 windmills; 3.1 MW from 7 hydro projects; 41 MW by 13 cogenerators; and 0.1 MW from one photovoltaic array.[52]

As indicated in Table 12, NEP currently offers no payment for capacity. The Companies justification for this policy is that SSP "have no dollar value to NEP because NEP's current reserve margin exceeds NEP's share of NEPOOL's required reserves."[53] Furthermore, with so much coal-fired, nuclear and hydro generation, NEP's avoided costs are relatively low. NEES believes that these low avoided energy costs and reluctance to pay for capacity that is not needed for over a decade could put the Companies at a competitive disadvantage in the SPP market.[54] Therefore, they are reevaluating their SPP contracting policies.[55]

C. Conclusions: Supply Plan

Based on NEES's current capacity surplus, its plans for capacity additions, and its contingency planning efforts, the Council finds that the Companies' supply plan provides an adequate supply of power throughout the forecast period even under severe contingency conditions.

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49. The Companies have indicated that they in fact intend to expand their research program in 1985 and 1986. Response to CLF Information Request 4.C. "Demand Side Planning Load Management and Conservation" dated October 25, 1984, p.5. CLF has stated that NEES' forecast underestimates conservation naturally occurring through improvements in end use efficiencies and available through aggressive program activities, which CLF believes can be cost-effective. CLF also criticizes NEES' adherence to the no-losers test. The Council has not examined these contentions in detail due to the agreement by the parties to undertake a review of cost issues in the next review.
50. Forecast, Volume 2, p.2.
51. Response to Information Request SP-9. The status of projects is based on the Companies' response to Staff information requests submitted on December 14, 1984.
52. Response to Information Request SP-10.
53. Response to CLF Information Request 2.c.
54. The Companies are firm believers in the competitiveness of the SPP market. As the Companies' Response to CLF's Information Request 4.g. indicates: "Supply and demand equilibrium in the small power producer market is in NEES' view extremely price sensitive for some projections."
55. Response to Information Request SP-8e.

Table 11

Full Scale Implementation of
Load Management Strategies

	Estimated Peak Load Reduction in 1998 (MW)	
	Winter	Summer
Controlled Electric Hot Water with Seasonal Control Schedules	10	80
Uncontrolled Electric Hot Water Converted to Seasonal Control	15	15
Promote Solar and Dual Fuel Heat Pump Heating Systems	25	5
Promote Storage Electric Heat	35	0
Electric Heat Peak Control Rate	30	0
Residential Central A/C Control	0	5
Industrial T.O.U. & Peak Control Rates	75	85
Commercial T.O.U. & Peak Control Rates	60	55
Commercial A/C Control	0	30
Interruptible Rates	35	35
Storage Cooling	0	40
TOTAL	285	350

Source: Forecast, V.1, p.110.

Estimates are goals based on reasoned judgements. Response to Information Request SP-3.

Table 12

Small Power Producers Under Contract to NEES

Project	MW	Fuel	In Service Date	Contract Terms
Lawrence Hydroelectric Lawrence, MA	15.3	Water	1978	23 years with option to extend Electric Energy*
West Dudley Hydro West Dudley, MA	.3	Water	1984	10 years Electric Energy*
Refuse Fuels[1] Lawrence, MA	7.5	Refuse	1984	25 years Electric Energy*
Mass. Refuse Tech. "NESWEC" North Andover, MA	30.0	Refuse	1985	20 years Electric Energy*
RESCO Saugus, MA	60.0	Refuse	1985	30 years Electric Energy*

Source: Response to Information Request SP-9, Forecast, Table E-24.

1. Rated Capacity of plant is 28.8 MW, 7.5 MW of which is available to NEP; the remainder is sold as electricity and steam to an adjacent industrial park.

* Note: NEP only pays for energy produced. There is no payment for the SPP capacity.

As agreed to by the parties in this proceeding, this Decision makes no findings as to whether the Companies' supply plan offers a least-cost supply with minimum environmental impact. Such issues will be adjudicated in the Council's review of the Companies' Supplement 2D to their Second Long-Range Forecast.

V. Order

The Siting Council APPROVES without conditions the demand portion of the Third Supplement to the Second Long-Range Forecast of electricity requirements and resources of Massachusetts Electric Company, New England Power Company, and Yankee Atomic Power Company. The supply plan portion of the Supplement is approved to the extent it demonstrates an adequacy of supply throughout the forecast period. As discussed herein, additional supply issues will be considered in Docket No. 85-24 as part of the review of the Fourth Supplement.

James G. White, Jr.
James G. White, Jr.,
Hearing Officer

Unanimously APPROVED by the Energy Facilities Siting Council on May 23, 1985 by those members and designees present and voting: Chairperson Sharon M. Pollard (Secretary of Energy Resources); Sarah Wald (for Paul W. Gold, Secretary of Consumer Affairs); Stephen Roop (for James S. Hoyte, Secretary of Environmental Affairs); Madeline Varitimos (Public Environmental Member).

24 May 1985
Date

Sharon M. Pollard
Sharon M. Pollard
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of the City of Westfield Gas and Electric Light Department for Approval of the 1984 Supplement to the Second Long-Range Forecast of Gas Requirements and Resources	Docket No. 84-26

FINAL DECISION

Carolyn Ramm
Hearing Officer

Calvin Young
Analyst

May 23, 1985

TABLE OF CONTENTS

I. Introduction

The Energy Facilities Siting Council ("Council") APPROVES the 1984 Supplement to the Second Long-Range Forecast of Gas Requirements and Resources ("Supplement") of the City of Westfield Gas and Electric Light Department ("Westfield"), subject to the Conditions imposed herein.[1]

A. History of Proceedings

Westfield filed the current supplement on September 17, 1984. Westfield provided public notice of the filing by publication and posting of Notice of Adjudication. The Siting Council received no intervention petitions. Westfield submitted responses to one set of Document and Information Requests.

B. Background

Westfield is a municipal utility and is the tenth largest distributor of natural gas in the Commonwealth in terms of annual gas sendout.[2] Table A reflects Westfield's total annual firm sendout and the average number of customers for split year 1983/84 by class.

Table A. Total Annual Firm Sendout and Average Customers 1983/84

	Annual Sendout (MMcf)	Average Customers
Residential Heat	469,066	4,197
Residential Non-Heat	57,035	1,558
Commercial	353,002	580
Industrial	64,118	18
Municipal	17,711	22
Company & Unacc't	146,428	-
Total Firm	1,107,360	6,375

Of the 6,375 average customers, 90 percent were residential customers and of the approximately 1.1 million Mcf of firm sendout, 64 percent went to residential with gas heat customers and commercial customers. Sendout to residential customers with gas heating, commercial customers and company and unaccounted for use represented 87 percent of total firm sendout for 1983/84.

Since the last filing, Westfield has added 71 commercial and 5

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1. The Energy Facilities Siting Council approved the First Annual Supplement to the Second Long Range Forecast in April, 1984. City of Westfield Gas and Elect. Light Dept., 11 DOMSC 149 (1984).

2. G. Aronson, Report of the Energy Facilities Siting Council, "The Gas Industry in Massachusetts" (March, 1983).

industrial customers.[3] The expected increase in residential customers with heat did not materialize. The pattern of declining numbers of residential customers without gas heating continued. Westfield expects to continue the trend of losing 15-20 residential customers without gas heating per year throughout the forecast period.

C. Prior Conditions

In its last decision involving Westfield, the Council imposed a condition "that the Department provide a forecast of peak day sendout requirements and reflect those requirements in the cold snap analysis".[4] Westfield complied with this condition in its 1984 Supplement. The Council also commends Westfield for submitting additional work papers used to derive past heating and base loads as suggested in the last decision.[5]

II. Scope and Standard of Review

The Commonwealth of Massachusetts mandates that the Council review sendout forecasts of each gas utility to ensure the accurate projection of gas sendout requirements of a utility's market area. The Council's Rules 62.9(2) (a), (b) and (c) require the use of accurate and complete historical data and a reasonable statistical projection method. In its review of a forecast, the Council determines whether a projection method is reasonable according to whether the methodology is: (a) appropriate or technically suitable for the size and nature of the particular gas utility's system; (b) reviewable or presented in a way that results can be evaluated and duplicated by another person given the same information; and (c) reliable, that is, provides a measure of confidence that the gas utility's assumptions, judgements and data will forecast what is likely to occur. The Council applies these criteria on a case-by-case basis.

In order to ensure that required gas is supplied to a utility's customers with a minimum impact on the environment at lowest cost, the Council focuses its supply review on adequacy, cost and reliability of gas supplies needed to meet projected sendout requirements. Adequacy of supply is measured by a company's ability to provide capacity sufficient to meet a projected peak day, a two week cold-snap, and total annual firm sendout with sufficient reserves to provide gas sendout throughout the year. The review of costs of supply addresses long-run cost minimization constrained by adequacy and reliability of natural gas supply. The reliability of supply reviews the probability that a

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3. From split year 1981/82 to split year 1982/83, industrial customers declined by seven from 20 to 13. The decline was attributed to fuel switching to oil from gas as reported in City of Westfield Gas and Electric Light Dept., 11 DOMSC 150 (1984).

4. 11 DOMSC at 158.

5. 11 DOMSC at 152.

specific source of natural gas will be available to meet or contribute to meeting sendout requirements for peak load or cold snap sendout requirements.

III. Forecast of Sendout Requirement

A. Overview of Forecast Methodology

The Council appreciates the expanded narrative of Westfield's filing as requested in City of Westfield Gas and Electric Light Dept., 11 DOMSC 151 (1984). The Council, however, requests the submission of all backup workpapers used in sendout forecasts in all future filings.[6] The Council also commends and encourages the continued computerization of Westfield's forecasts. Westfield has developed its forecast using the same methodology employed in previous filings.

This forecast uses a methodology developed by the American Gas Association for small gas distribution companies.[7] Westfield generates normal and design year forecasts by customer class. For each class, the following formulas are used to project normal year and design year sendout respectively:

(1) [(class average number of customers) x (class base load factor) x 365] + [(class average number of customers) x (class heating load factor) x (normal year degree days)]

and

(2) [(class average number of customers) x (class base load factor) x 365] + [(class average number of customers)x (class heating factor) x (design year degree days)].

Westfield constructs base load and heating load factors for each class of customers from its most recent split year.[8] The base load is derived from sales data for the months of June, July and August. In each year, base load factors are adjusted for conservation. A heating load factor for each class is calculated by subtracting base load from total sendout and dividing the remainder by the average number of customers and by the number of degree days. Heating load factors are adjusted judgementally for conservation, and improvements in appliances and machinery. Projections of heating load by class are compiled by multiplying projected average number of customers times the adjusted heating load factors and normalized (or design) degree days. Base load is added to heating load to obtain total class sendout.

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6. The submission of work and backup papers enhances the reviewability of the filing and minimizes the need for information requests.

7. See American Gas Association, A Simplified Approach to Forecast Gas Sales and Revenues: For the Small Gas Distribution Company, 1983.

8. In this filing Westfield developed its base load and heating load factors from consumption data for split year 1983/1984.

Individual customer class projections are summed and added to company use and unaccounted-for sendout projections to derive total firm sendout. Projected average number of customers are determined from historical data and an intimate knowledge of the community.

The Council generally finds Westfield's methodology to be sound and appropriate relative to the size and resources of the Company.[9] Further, Westfield's submission of backup work papers was essential documentation that enabled the Council to conduct its review.

B. Weather Data Problems

However, the Council is unable to completely review Westfield's forecast due to the Company's reliance upon faulty degree day data which bias the calculation of heating load factors used in the projection of sendout for all customer classes. Therefore, the forecast is not reliable. The Council expects Westfield to address the problem of accurately recording degree days and their impact upon sendout projections in its next filing.

Westfield uses a 65° Fahrenheit standard as the temperature above which heating load is zero. Westfield employs this standard to derive degree days as a measure of coldness in determining normal and design year planning criteria, and to forecast heating load increments.[10]

Degree data in Westfield's 1984 Supplement is presented in Table B. Initially, Westfield reported split year 1983/84 as a design year, the coldest year in the past seventeen split years. In response to Requests for Documents and Information ("Information Requests") nos. I.17- I.20, Westfield amended the degree days for split year 1983/84 to 1317, 5075 and 6392 for non-heating season, heating season and total degree days respectively.[11] The Council notes that the adjusted data are consistent with degree day data of Berkshire Gas Company ("Berkshire") and Holyoke Gas and Electric Light Department ("Holyoke"). As indicated in Table C, the two neighboring utilities, Berkshire and Holyoke, reported split year 1983/84 as a warmer than normal year.

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9. The appropriateness of a methodology for a gas utility depends upon the size of the market and the resources available to the Company. See N. Attleboro Gas Co., 10 DOMSC 159, 160 (1984), for standards set for a utility of similar size and resources to Westfield.

10. The number of degree days in a day is calculated by subtracting the average temperature from the standard, i.e. 65°F. Average temperature is the day's high temperature plus the day's low temperature divided by two.

11. In response to Information Requests nos. I.17-I.20, Westfield stated that temperature readings were taken from a Taylor temperature recording instrument at its Dispatch Center. The instrument was reading two degrees too low. This reading lead to incorrect degree days for 1983/84.

Table B Degree Day Data

Split Year 4/1-3/31	Non-Heat Season	Heat Season	Total Split Year
1978/80	1534	4802	6336
1980/81	1207	5129	6336
1981/82	1382	5256	6638
1982/83	1450	4530	5980
1983/84	1652	5377	7029
Normal	1412	5092	6504
Design	1652	5377	7029

Also, the adjusted degree day data for Westfield indicates a warmer than normal year. In addition, actual total firm sendout for 1983/84 was 1,107,360 MCF, while the normal year sendout forecasted in the 1983 Supplement was 1,183,022. This indicates further that split year 1983/84 was a warmer than normal split year.[12]

Table C
Comparison of Degree Days of Westfield
with Berkshire and Holyoke

	Split Year 1983/84	Normal Year	Design Year
Berkshire	7,353	7,462	8,140
Holyoke	6,080	6,505	6,985
Westfield	6,392	6,472	6,954

The unreliability of this aspect of the forecast has the Council concerned. The Council recommends that Westfield re-evaluate its source of weather data. Specifically, Westfield should explore the degree day data sources of Holyoke and the Massachusetts Municipal Wholesale Electric Company. Also, Westfield should investigate the reliability of temperature readings at Springfield Airport and Barnes Air Base. Condition 1 addresses this data issue.

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12. Only residential customers with heating fell short of the 1983 Supplement's forecast for 1983/84. There were more customers in the residential without gas heating, commercial and industrial classes than the 1983 Supplement had projected. These increases should have more than accounted for any reductions in sendout to the residential heating class.

C. Criteria and Assumptions for Weather and Conservation

1. Design Year Criteria

In Docket No. 80-26, the Council required Westfield to change its calculation of design year degree days from the sum of the coldest heating season degree days and the coldest non-heating season degree days.[13] In the 1981 filing, Westfield responded to the Council's condition and based its design year degree days on the coldest split year. In its 1983 and 1984 filings, Westfield reverted to using the sum of the coldest heating season degree days and the coldest non-heating season degree days in constructing the design year. The Council reminds Westfield that this method of determining its design year is inappropriate and recommends that Westfield alter its criteria and use an acceptable criteria in all future filings.

2. Peak Day Criteria and Sendout

The peak day standard is 69 degree days which occured in split year 1980/81 representing the coldest day in seventeen years. Peak day sendout is projected to decline from 6687 Mcf in 1984/85 to 6311 Mcf in 1988/89. However, Westfield's peak day degree days for 1983/84 totaled 63 and sendout was 7482.[14] Furthermore, the peak day sendout for internal planning purposes in 1984/85 is 7935.[15] Therefore, the Council believes that the peak day sendouts forecasted in the 1984 Supplement are too low.

3. Two Week Cold Snap Requirements

The standard for Westfield's two week cold snap is the coldest two week period in the last seventeen years. This actually occurred in split year 1980/81. The degree days range from 25 to 69 during this period. Forecast sendout steadily declines from 69,108 Mcf in 1984/85 to 65,982 in 1988-89. Again, the Council believes these estimates are too low due to underreporting of degree days which produced heating load factors which are too low.

4. Conservation

Westfield promotes conservation of gas through bill stuffers, booklets, and other promotional literature.[16] Staff limitations restrict Westfield's ability to initiate an extensive conservation program. However, Westfield does coordinate its efforts with MASS SAVE

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13. 8 DOMSC at 168.

14. Due to data bias the actual peak degree day may have been 61.

15. From Daily Dispatch Log submitted to the Council in response to Information Requests no. IV.4.

16. See 8 DOMSC at 169 and response to Information Request no. A.4 in Docket No. 83-26.

through an intensive telephone soliciting plan to encourage home energy audits. To help to account for the effects of Company sponsored and customer conservation, Westfield has stated in its 1981 Forecast that it makes judgemental adjustments to its sendout forecasts. The resultant declining normalized sendout by classes are indicative of Westfield's expectations about conservation efforts of its customers which outweighs projected increases in the number of customers in four customer classes.

D. Forecast of Total Firm Sendout

1. Overview

The 1984 Supplement's forecast of sendout in both normal and design split years are underestimated due to Westfield's use of inaccurate degree day data leading to underestimates of heating load factor.[17] Westfield constructed its heating load factors for each class using 7029 degree days instead of 6392 degree days. Heating load factors are calculated as follows:

$$\frac{\text{(1983/84 Class Sendout)} - \text{(1983/84 Class Base Load)}}{\text{(1983/84 Number of Customers by Class)} \times \text{(1983/84 total degree days)}}$$

The impact Westfield's use of inaccurate degree day totals is to reduce heating load of each class. Throughout the forecast heating loads appear to be underestimated by approximately ten percent. Accordingly, total sendout for normal and design years should be increased for each forecast year by about 50,000 Mcf and 53,000 Mcf respectively.

2. Normal Year

Table D Forecast of Normal Year
Sendout in the 1983 and 1984 Supplements

	1983 Filing			1984 Filing (uncorrected)		
Year	Non-Heat	Heating	Total	Non-Heat	Heat	Total
1984/85	433,549	738,773	1,172,322	389,703	636,320	1,026,023
1985/86	427,445	733,619	1,164,065	389,478	623,933	1,013,411
1986/87	421,364	720,000	1,149,564	387,795	599,606	987,401
1987/88	415,314	722,527	1,137,841	388,694	599,802	988,496
1988/89	-----	-----	-----	389,506	589,863	979,369

17. Heating loads are underestimated for two reasons. For each class, the heating load factors are underestimated by about 11 percent. The heating load is, also, affected by higher design and normal year degree days. Westfield used 6504 and 7029 for normal and design year degree days instead of 6472 and 6954. However, for each class, this increases the heating load by 0.4 percent and 1.1 percent in a normal and design year respectively. Therefore, the net underestimation of heating loads is about ten percent for both normal and design year sendout forecasts.

Table D compares the forecast for normal years 1984/85 through 1987/88 in the 1983 and 1984 Supplements. The Council is disturbed by the substantial difference in sendout projections between the forecasts. The 1983 Supplement exceeds the 1984 Supplement by 146,000 Mcf in 1984/85 and 158,000 Mcf in 1987/88. The biased heating load accounts for about a third of this difference. Taking this into account, a ten percent difference between the forecasts remains, which Westfield has not explained.

3. Design Year

Table E compares the design year forecasts for 1984/85 through 1987/88 in the 1983 and 1984 Supplements. Again, the Council is concerned about the substantial difference in sendout projection for design years. After the 1984 projections are corrected the difference is about 180,000 Mcf in 1984/85 and 173,000 Mcf in 1987/88. The net difference is approximately 17 percent. As will be shown, the difference in projections seems to be due to load factors of varying size.

Table E Forecast of Design Year Sendout
in the 1983 and 1984 Supplements

	1983 Filing			1984 Filing (uncorrected)		
Year	Non-Heat	Heat	Total	Non-Heat	Heat	Total
1984/85	476,904	812,650	1,289,554	406,334	659,585	1,065,919
1985/86	407,190	806,981	1,277,171	406,228	646,305	1,052,533
1986/87	463,500	801,020	1,264,520	404,356	631,368	1,035,724
1987/88	456,945	794,780	1,251,625	405,044	620,998	1,026,042
1988/89	-----	-----	-----	406,793	610,630	1,016,423

E. Forecast of Sendout by Customer Class in the 1984 Filing

1. Residential with Gas Heat

The average number of customers is projected to increase by 21 per annum from 1983/84 until 1986/87 and by 57 thereafter. The 1983 Supplement had predicted an increase of 42 customers while only an increase of 5 customers was realized. Westfield did not provide an explanation of the difference between the increase in the number of customers projected in the 1983 Supplement for split year 1983/84, and the actual increase in customers realized in 1983/84. There are two sources of increase in residential customers with gas heating: (a) additions to the system and (b) conversions of residential customers without gas heating to gas heating. The smaller than expected increase in residential customers with heating must be attributed to fewer than expected additions to the system, since there was a greater than expected decline in residential domestic customers which Westfield attributes in part to conversion to residential customers with gas heat. Information Request no. I.5.

Table F Heating Load and Base Load Factors by Class

Base Load Factors	Residential Domestic	Residential Heat	Commercial	Industrial	Municipal	Department
1975/76	0.07415	0.13134	0.40218	14.14333	3.28714	0.144
1976/77	0.07148	0.13307	0.61677	10.04556**	0.86539	0.28
1977/78	0.07244**	0.12297	0.4224	10.18611	1.22154	0.146
1978/79	0.07386	0.12789	0.46603**	11.32333	1.06514	0.21
1979/80	0.0744	0.12432**	0.40609	9.72445	0.58111	0.19 **
1980/81	0.06664	0.10972	0.47027	8.99524	0.62444	0.13
1981/82	0.0641	0.10611	0.45933	11.155	0.65389	0.19565
1982/83	0.06617	0.11156	1.17611	7.26171	0.63804	0.16087
1983/84	0.07432	0.12703	0.85765	7.20531	0.66674**	7.5587
Heating Load Factors						
1975/76	0.00072	0.01292	0.04018	0.21627	0.26458	0.06397
1976/77	0.00118	0.01338	0.03921	0.62833	0.20274	0.0737
1977/78	0.00098	0.0118	0.04051	0.20805	0.19147	0.07788
1978/79	0.00092	0.01192**	0.04532	0.23141	0.17013	0.07555
1979/80	0.00127**	0.01083	0.04695	0.45335	0.12304	0.07146
1980/81	0.00195	0.01233	0.05303	0.51279	0.13785**	0.07519**
1981/82	0.00199	0.01234	0.07765	0.38849	0.12677	0.08838
1982/83	0.00177	0.01041	0.06778	1.49123***	0.10122	0.08402
1983/84*	0.00133	0.00929	0.04193**	0.13159	0.07981	0.07189

* The 1983 Heating load factors are uncorrected in this table and should be adjusted upward by 11 percent to correct for degree day data errors.

** Median

*** See Footnote 21

Base load and heating load factors are projected to decline by one and two percent per annum respectively.[18] There are several potential causes of a decline in residential load factors. These include customer conservation efforts, more efficient appliances, smaller housing units, customer behavioral response to price change and family size. However, as the historical record indicates load factors vary in both directions in response to price, income, family size and housing unit type. Only the base load factor exhibits a clear declining trend. Forecasts of residential heating sendout might be subject to less variation and be more accurate if load factors were constructed by some method other than the current year's data. An example might be to average the factors for the five most recent split years. Given the significance of residential heating sendout, this would be a worthwhile improvement.

Residential-with-heat base and heating load factors have been extremely stable. As shown in Table F, base load factors have varied from the median of 0.12432 Mcf by ± 0.0018 Mcf or approximately 15 percent. Heating load factors vary about the median of 0.01192 Mcf by ± 0.0015 Mcf or about 12 percent.[19]

Load factors vary significantly from year to year within a narrow range. Accordingly, residential heating sendout forecasts vary from year to year, since they are based upon yearly load factors. In addition, the difference between forecast sendout and actual sendout is likely to be greater for a forecast based upon load factors constructed from a year's data than for a forecast based upon an average of load factors constructed from yearly data. Therefore, the Council ORDERS in Condition 2 that Westfield:

(a) evaluate its forecast of residential heating sendout for a normal year based upon load factors as constructed from a year's data compared to some average of yearly load factors, and
(b) evaluate its forecast of residential heating sendout in a design year based upon the most recent year's load factors as compared to some other year's load factor such as the highest load factors in the previous five year period.

2. Residential Without Gas Heating

The number of customers is projected to decline by sixteen per year from its current level of 1558. The 1983 Supplemental forecasted a decline of ten customers for split year 1983/84. The actual decline was

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18. Westfield projects in its back-up workpapers a decrease in the load factors. These percentage reductions should not be affected by correcting the heating load factors in any customer class.

19. When the 1983/84 heating load factor is adjusted by 11 percent its becomes approximately 0.01031 and falls within the range.

twenty-five customers. Westfield states that the decline is caused by conversion to residential heating and fewer than expected customer additions. Information Request no. I.5.

Base and heating load factors are projected to decline by one and two percent respectively.

As shown in Table F, base load factors vary by .008 Mcf about the median of 0.07244 Mcf. Heat load factors fluctuate by 0.0007 Mcf about a median of 0.00127 Mcf. However, heating load factors exhibit an increasing trend over the past five years.

3. Commercial

The Council is concerned about the significant difference between the actual and forecasted increase in customers. The number of customers is projected to increase by six per year throughout the forecast from the current level of 1558. The 1983 Supplement forecasted an increase of two commercial customers; the actual increase was seventy-one. In response to Information Request no. I.6 Westfield explains the failure to project the significant increase as computer error. The Council is concerned as knowledge of commercial activity would be a significant determinant of forecast of the number of customers. And this failure is indicative of limited knowledge of the commercial sector, not just a mechanistic error.

In future years, Westfield expects heating and base load factors to decline by two and one-and-one-half percent respectively.

Load factors for the commercial class have been extremely volatile.[20] When adjusted, the 1983/84 heating load factor would be the median of approximately 0.0466 Mcf. The 1981/82 heating load factor of 0.07765 was about 70 percent greater than the median. Also, there appears to be an increasing heating load factor trend. The median of base load factors is 0.46603 Mcf, with the highest base load factor being 1.17611 Mcf in 1982/83. The last two years have been abnormally high.

Within a somewhat wide range heating load factors have significant variance and have exhibited no clear trend in the past five years. Therefore, the forecasts of commercial sendout have exhibited variation. Consequently, the Council ORDERS in Condition 2 that Westfield:

(a) evaluate its procedure for forecasting commercial heating loads and research alternative methods for estimating heating load in a normal year, such as a weighted average of heating load factors, and
(b) re-evaluate its procedure for forecasting commercial heating load in a design year and research alternatives such as the largest heating load factor in the past five years.

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20. This is expected as the economy would have significant impact on commercial and industrial activity.

4. Industrial[21]

Westfield projects an increase in the number of industrial customers of one per annum from the current level of eighteen.[22] The number of customers increased by five in split year 1983/84.

Base and heating load factors are both projected to decline by one percent.

Again, as shown in Table F, base and heating load factors have exhibited significant variation over a wide range. Base load factors show a substantial decreasing trend. Heating load factors show no trend.

The Council suggests that Westfield evaluate its heating load factors along lines similar to those suggested for commercial customers.

5. Municipal

The number of customers in the municipal class is expected to increase to twenty-four from the current level of twenty-two. Base and heating load factors are both expected to decline by one percent.

For the past five years, base load factors have varied within a narrow range. Over the past five years, base load factors have increased from 0.58111 Mcf to 0.66674 Mcf, representing a thirteen percent increase over four years. The heating load factor has shown a decreasing trend. Heating load factors have a high of 0.13785 Mcf and a low of approximately 0.8759 Mcf over the last five years.

6. Company and Unaccounted

Company use and unaccounted-for sendout in the heating season increased by nearly 300 percent from 37,193 Mcf in 1982/83 to 129,156 Mcf in 1983/84. Also, there was more than a 100-percent increase between 1979/80 and 1980/81 alone when sendout increased from 62,720 Mcf to 138,002 Mcf. Westfield "suspects" an accounting error occurred.[23] Liquified Natural Gas ("LNG") and Liquified Propane Gas ("LPG") inventories may have been included in the unaccounted-for gas. The Council is concerned that Westfield correct this suspected error in future forecasts.

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21. In 11 DOMSC at 151, the Council noted a data error existed in industrial sendout. The forecast of industrial sendout was 122,360 Mcf in split-year 1982/83. In response to Information Requests in Docket No. 83-26, the sendout was amended to 35,000 Mcf. This error was repeated in the 1984 Supplement.

22. In split year 1982/83, the number of industrial customers declined by seven.

23. In Response to Information Request no. I.13.

The base load factor for 1983/84 was 7.5587 Mcf while the previous high base load factor was 0.28 Mcf for 1977/78. Again, the impact of this suspected forecast error would be less severe if an average of load factors were used.

The 1983 Supplement projected increasing sendout beginning at 11,278 Mcf in 1983/84, and rising to 12,384 Mcf in 1987/88. In the current filing, sendout is projected to decline from 93,548 Mcf in 1984/85 to 56,082 in 1988/89.

7. Resale and Interruptible Sendout

In the past, Westfield has sold excess pipeline gas to Bay State Gas Company ("Bay State"). Westfield's last sale of excess pipeline supplies was in November, 1982.[24] Westfield anticipates no future sales to Bay State.

Westfield has one interruptible customer which does not receive gas on peak days. This customer receives gas during the heating season only to the extent possible.[25] Westfield forecasts modest increases in sales to the customer from 26,142 Mcf in split year 1984/85 to 27,204 Mcf in 1988/89.

F. Summary and Conclusions

Westfield forecasts sendout using a methodology developed by the American Gas Association which the Council considers appropriate for utilities of modest size and resources. The Council applauds Westfield's inclusion of an expanded narrative as requested in the previous Decision. Also, Westfield submitted a forecast of peak day sendout requirement in compliance with the condition of the Council's last decision. In addition, the Council commends Westfield for submitting back-up workpapers used in forecasting sendout and encourages Westfield to continue this practice in the future. Furthermore, the Council encourages and lauds Westfield's efforts to computerize its forecast methodology.

However, the overall forecast as submitted has several flaws. First, Westfield's faulty degree day data limited the Council's ability to provide a complete review of the forecast. The Council registers its concern about Westfield's source of data and ORDERS in Condition 1 that the Company explore alternatives to the present source of data.

Second, the Council recognizes the Company's reliance on its judgement and intimate knowledge of community affairs is indispensable in developing reliable forecasts for companies of Westfield's size and resources.[26] However, past forecasts said to be based on such judgement

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24. See 11 DOMSC at 153.
25. Ibid.
26. In 11 DOMSC at 152, the Council noted "that Westfield should demonstrate its use of its intimate knowledge of the community to adjust the output of its next filing."

and knowledge have proven possibly inaccurate; there is a substantial difference between the 1983 Supplement's forecast and the actual increase in commercial customers in 1983/84. Load factors have varied unexpectedly especially with respect to industrial and commercial classes. The Council is concerned that these errors indicate that the Company is not aware of important activities occurring in the community or is not taking care to insure that the numbers in the forecast reasonably reflect what the company's judgement leads it to believe is occurring or will take place in the future. Condition 6 addresses this concern.

Next, the Council questions the construction of a sendout forecast based only upon the current year's load factors, resulting in larger fluctuations of forecasts from year to year and in larger differences between the actual and forecast sendout than a weighted average of load factors might produce. A complete review of this procedure by Westfield is ORDERED in Condition 2.

Finally, Westfield reverted to a coldest heating season plus coldest non-heating season criterion for a design year in both the 1983 and 1984 Supplements. This criterion was rejected by the Council in two different decisions.[27] An alternate criterion needs to be developed, and Condition 4 addresses this need.

Nevertheless, the Council APPROVES the forecast of the 1984 Supplement subject to CONDITIONS imposed in section VI. Westfield's methodology is sound and of a quality comparable to gas utilities of similar size and resources. Moreover, Westfield has been responsive to some of the Council's concerns.

Still, a need remains for Westfield to improve the reliability of its forecast, and the conditions attached to this Decision are aimed at moving the Company in this direction. In future filings, failure of Westfield to demonstrate significant progress towards increasing the reliability of its forecast will be cause for rejection.

The prime concern of the Council -- and the purposes of the conditions attached to this Decision -- is that Westfield have a reliable forecast so that it can develop an adequate, least cost supply plan prior to negotiating new contracts with gas suppliers.

IV. Resources and Facilities

Westfield relies on pipeline gas purchased from Tennessee Gas Pipeline Company ("Tennessee") to meet most of its sendout requirements. During cold weather, Westfield also sends out LNG and propane-air.

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27. See 4 DOMSC at 218 and 6 DOMSC at 64.

Westfield purchases gas under Tennessee's G-6 Rate Schedule pursuant to a contract dated October 9, 1981. The initial termination date of the contract is November 1, 2000 with automatic annual extensions unless cancelled on twelve months' written notice of either party. The maximum daily quantity ("MDQ") is 5.079 MMcf. The annual volumetric limitation ("AVL") is 1854 MMcf, representing the MDQ times the days in each year. Also, Westfield has available additional supplies of Tennessee R-6 Rate Schedule gas on a non-firm basis.[28]

Westfield purchases LNG from Bay State Gas Company pursuant to a contract dated October 25, 1978, as amended on August 23, 1982. The contract has an initial expiration date of March 31, 1988, but will continue in effect on a contract-year basis thereafter unless cancelled on twelve months' written notice of either party. The August 1982 amendment provides for increased quantities of both firm and optional supplies from Bay State throughout the forecast period. As amended, the contract provides for 73 MMcf of firm volumes and 23 MMcf of optional volumes.

Westfield purchases the firm quantities of LNG on a take-or-pay basis. Westfield exercises the option to purchase additional volumes on ten days' notice prior to the month in which the gas is to be made available. The elected optional quantities become the take-or-pay responsibility of Westfield.

Under the Bay State contract, Westfield is obliged to use its best efforts to receive the gas by displacement (pursuant to one hour advance notice from Westfield) through an interconnection between the two companies on Westfield Street in North Agawam. The contractual maximum hourly rate of delivery by displacement is 50 Mcf. If the gas cannot be delivered by displacement, delivery is accomplished by LNG (or propane at Westfield's option) truck transportation provided by Bay State. Westfield requests truck deliveries on twenty-four hours' advance notice, but is constrained to request delivery in full truckloads. Westfield's LNG facility has a design maximum daily sendout of 12 MMcf, which is greater than the total storage capacity of 9.1 MMcf. During the 1982/83 split year, the total LNG sendout from storage was 16.3 MMcf, and the maximum daily sendout was 2.02 MMcf.

Westfield's propane facility has a storage capacity of 8.49 MMcf and a design maximum daily sendout of 1.2 MMcf. During the 1982/83 and 1983/84 split years, however, Westfield had no propane sendout. Westfield's current filing indicates no existing propane supply contracts through the forecast period.[29]

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28. An invoice forwarded to the Council in response to Information Requests nos. IV.6 and IV.7 indicates that Westfield purchased additional volumes from Tennessee under the R-6 rate schedule. During the 1984/85 heating season, Westfield will purchase at least 2,575 Mcf of R-6 gas.

29. Westfield intends to assess its need for propane during the non-heating season and purchase available Summer inventories, if necessary, in response to Information Request no. II.3.

Table G
Comparison of Resources and Requirements
during a Normal Year
(MMcf)

	84/85	85/86	86/87	87/88	88/89
Requirements					
Firm	1,026.0	1,013.4	997.4	988.5	979.4
Interruptible	26.1	26.4	26.7	26.9	27.2
LNG Storage Refill	7.9	7.9	7.9	7.9	7.9
Total	1,060.0	1,047.7	1,032.0	1,023.3	1,014.5
Resources					
Tennessee G-6	979.1	966.8	951.1	942.4	1,006.6
Bay State[a]	73.0	73.0	73.0	73.0	0
LNG (storage)	7.9	7.9	7.9	7.9	7.9
Propane	0	0	0	0	0
Total	1,060.0	1,047.7	1,032.0	1,023.3	1,014.5

Table H
Comparison of Resources and Requirements
During a Design Year
(MMcf)

Requirements					
Firm	1,065.9	1,052.5	1,035.7	1,026.0	1,016.4
Interruptible	26.1	26.4	26.7	26.9	27.2
LNG (storage)	7.9	7.9	7.9	7.9	7.9
Total	1,099.9	1,086.8	1,070.3	1,060.8	1,052.7
Resources					
Tennessee G-6	1,017.6	1,004.5	988.0	978.5	1,043.4
Bay State[a]	73.0	73.0	73.0	73.0	0
LNG (storage)	7.9	7.9	7.9	7.9	7.9
Propane	1.4	1.4	1.4	1.4	1.4
Total	1,099.9	1,086.8	1,070.3	1,060.8	1,052.7

a. In split-year 1988/89, Westfield resources reflect the non-renewal of their contract for supplemental gas from Bay State.

The Council notes that Westfield is negotiating with Tennessee for additional gas quantities under the G-6 Rate Schedule.[30] The scheduled agreement would increase Westfield's maximum daily quantity to 8594 Mcf for split year 1985/86 and beginning in split year 1986/87 maximum daily quantity becomes 8,754. The corresponding annual quantities are 3,136,810 Mcf and 3,195,210 Mcf respectively. The Council recognizes that these quantities cannot be reflected in Westfield's 1984 filing as these are not yet firm commitments. The Council finds that Westfield would have sufficient supplies from Tennessee to meet sendout requirements for the forecast period if this contract is actuated. Therefore, Condition 7 ORDERS Westfield to evaluate the need for a future agreement for continued gas supplies from Bay State, an agreement which is due to expire as soon as March 31, 1988.

V. Comparison of Resources and Requirements

A. <u>Normal Year</u>

Table G portrays Westfield's plan for meeting sendout requirements in a normal season. Requirements are met with purchases of Tennessee pipeline gas, Bay State firm supplies and stored LNG. Propane gas and Bay State optional supplies are not used.[31] Westfield sends out all of its Bay State firm quantities, but less than the available Tennessee G-6 is used. The excess above AVL is 874.9 MMcf in 1984/85 and 847.4 MMcf in 1988/89. Tennessee R-6 gas, Bay State quantities and stored LNG are used for peak shaving.

In spite of at least a ten percent underestimate of sendout, sufficient resources are available to meet requirements of its firm customers without significant disruptions to interruptible customers. If Westfield's forecast of a normal year's sendout were corrected to account for data errors, Westfield's firm sendout, except for peak shaving, could be met by Tennessee G-6 supplies alone.

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30. Tennesse has filed with the Federal Energy Regulatory Commission for an increase in Westfield's MDQ to 6250 dekatherms (5866.6 Mcf) and a decrease in AVL to 1,342,884 dekatherms (1,307,579.36 Mcf.) A conversion factor of 1.027 was used. Tennessee filed on April 17, 1985 and hopes for a successful conclusion which would enable implementation by November of 1986. Also, Westfield and Tennessee are negotiating a Precedent Agreement that would permit Westfield to raise its MDQ to 8,738.07 Mcf given two years notice.

31. In response to Information Request no. IV.4, the Daily Dispatch Log indicates no propane gas or Bay State optional volumes were sent out during the 1984/85 heating season. The peak sendout was 7801 Mcf. Also, Westfield plans for a peak day sendout of 7935. Since the 1984 Supplement's projected peak day sendout is 6687 Mcf, the Council is concerned that the forecast submitted to the Council is not used for internal planning purposes.

B. Design Year

Table H gives Westfield's plans for meeting requirements in a design year. Requirements are met with Tennessee pipeline gas, Bay State firm supplies, propane and stored LNG. Bay State optional supplies are not used. Westfield sends out all of its Bay State firm quantities, but less than the available Tennessee G-6 is used. The excess above AVL is 874.9 MMcf in 1984/85 and 810.6 in MMcf in 1988/89. Tennessee R-6 gas, Bay State quantities, propane and stored LNG are used for peak shaving.

Again, sufficient resources are available to meet requirements of its firm customers without significant disruptions to interruptible customers, even though this filing's forecast of design year sendout is reduced as compared to the 1983 Supplement.[32]

C. Peak Day

In addition to having sufficient gas supplies to meet seasonal and annual requirements of its customers, a gas utility must have sufficient daily pipeline supplies and facilities to meet peak day requirements of its firm customers.

The projected maximum total daily quantity available for a peak day sendout, as reported in this filing, is 13,200 Mcf. This compares to Westfield's forecast of peak day sendout of 6687 Mcf in 1984/85 declining to 6311 Mcf in 1988/89. The Council questions Westfield's assumption of the reliability of LNG supplies (other than displacement) and the assumption of propane and LNG storage at maximum capacity. Under the three assumptions given in the cold snap analysis, there would be available 10,191 Mcf for sendout on a peak day. Prior to 1988/89, Westfield would need to produce no more than 408 Mcf on a peak day. However, Westfield's peak day sendout was 7482 in 1983/84. Consequently, 1203 Mcf of production was necessary in 1983/84. This implies eight straight peak days could be met with stored propane and LNG.[33] Using the 1984/85 peak day sendout of 7801, production would

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32. The Council's analysis of total firm sendout in a design year in section III.C.3 indicates that the 1984 filing's unadjusted sendout is about 230,000 Mcf less than 1983 filing sendout. This is an appproximate difference of 22 percent. This is consistent with the peak day sendout in the Daily Dispatch Log exceeding the 1984 filing's peak day sendout by 19 percent. Increasing the projected sendout by 230 MMcf still leaves a considerable amount of Tennessee G-6 gas available.

33. The assumptions are very restrictive. Westfield is able to sustain a much longer period of sustained cold weather than indicated in the analysis that follows. In response to Information Requests nos. III.3 and III.9, Westfield states their experience with LNG deliveries by truck has been very reliable. Westfield does not expect any delays of more than twelve hours. Furthermore, included in the 1984/85 peak day sendout is Tennessee R-6 gas.

increase to 1522 Mcf, and six days of peak day sendout could be sustained. Employing a peak day sendout of 7935 Mcf, production would increase to 1654 and six days of peak day sendout can be sustained.

Assuming no Bay State LNG in 1988/89, the production of sendout increases by 1200 Mcf under each of the scenarios for peak day sendout. For a peak day sendout of 7935 Mcf, production[34] would become 2854 and Westfield can sustain three days of sendout.

D. Two Week Cold Snap

The Council has defined a "cold snap" as a period of peak or near-peak weather conditions, similar to the two-to-three week period experienced during the 1980/81 heating season. The Company's ability to meet the requirements of its customers during a cold snap depends on its daily pipeline entitlements, its daily supplemental sendout capacity and its storage inventories.

The Company is in a comfortable position with regard to its ability to meet sustained periods of extreme sendout. Only on a peak day during a two week cold snap would Westfield have to use gas other than Tennessee pipeline and Bay State displacement. On such peak days, Westfield would have to produce at most 1500 Mcf of supplemental sendout during the forecast period. Given the daily sendout capacity of 10,300 Mcf, Westfield would be able to meet peak day production of 1500 Mcf even if storage is well below capacity. Westfield's estimate of its ability to provide service during a cold snap is based on assumptions that: 1) no LNG or propane would be available by truck, 2) LNG storage is at 70 percent, and 3) propane storage at 45 percent of capacity. In this scenario, 10,191 Mcf is available for sendout in addition to 6279 Mcf of daily pipeline supply. Table I shows the results of this analysis.

A more realistic cold snap analysis would increase sendout forecast by approximately twenty percent. Under this scenario production would occur on three days. At 56 degree days, an adjusted sendout of 6840 Mcf would require 561 Mcf of production. At 63 degree days, sendout would be 7478 Mcf, requiring 1199 Mcf of production. (Parenthetically, this compares with the 1983/84 actual peak day of 63 degree days which had a sendout of 7482 Mcf). At 69 degree days, Westfield would plan for 7934 Mcf of sendout, requiring 1656 Mcf of production.

E. Summary and Conclusion

The Council's mandated task is to review gas utilities' plans to meet forecasted sendout requirements to ensure adequacy, reliability, and minimum cost of supply taking into account the variability of sendout due to weather and other considerations. The Council finds

34. Westfield should have submitted its internal planning figure, not 6682 Mcf for peak day sendout.

Table I.
Westfield's Two Week Cold Snap Analysis
(Mcf)

Split Year 1984/85

Fore-casted Degree Days	Total Sendout Required	Tennssee MDQE	Peak Shaving Required	Bay State Interconnect	Production Requirements
69	6687	5079	1608	1200	408
46	4942	4942	0	0	0
42	4638	4638	0	0	0
35	4107	4107	0	0	0
25	3348	3348	0	0	0
43	4714	4714	0	0	0
47	5018	5018	0	0	0
42	4638	4638	0	0	0
48	5093	5079	14	14	0
56	5700	5079	621	621	0
63	6232	5079	1153	1153	0
47	5018	5018	0	0	0
36	4183	4183	0	0	0
44	4790	4790	0	0	0
643	69108	65712	3396	2988	408

a. These sendout figures are approximately 20 percent too low. See p. 22, <u>infra</u>.

b. For internal planning purposes Westfield employs a peak day (69 degree day) sendout figure of 7935 Mcf, which is inconsistent with these figures.

Source: The <u>1984 Supplement</u>.

Westfield's plan to meet forecasted sendout requirements during a design year, two week cold-snap and peak day to be <u>adequate</u> and <u>reliable</u>.

On a peak day, pipeline supplies are 6,279 Mcf. Under reasonable assumptions of storage reserves, Westfield would have available an additional 7,570 Mcf of gas, well above peak day requirements approximating 8,000 Mcf. Pipeline supplies would be sufficient to meet daily requirements on most days and only on days where degree days exceed 63 would the 10,191 Mcf of stored supplemental capacity be needed.

Therefore, the Council APPROVES the supply portion of the 1984 Supplement subject to CONDITIONS imposed in Section VI.

Still, the Council is concerned that Westfield's supply plan exceeds minimum cost.

While lacking the information to fully evaluate the cost issues, the Council views the Company's excess supply situation as an indication that its supply plan may exceed minimum cost. Continued reliance on Bay State LNG and propane supplies may be unnecessary costs to Westfield's customers. Westfield should evaluate the need to continue its Bay State contract under current terms beyond March 30, 1988. An agreement with Tennessee would make the reassessment of a continued relationship with Bay State critical. The Council ORDERS Westfield in Condition 7 to indicate how it plans to evaluate the usefulness of contracting with Bay State for LNG beyond March 30, 1988.

The Council's analysis of Westfield's 1984 Supplement and information responses strongly suggests that Westfield should explore and evaluate possibilities of increasing its Tennessee G-6 MDQ, reducing its Tennessee G-6 AVL and terminating its Bay State contract. There is every indication that the Company is pursuing these objectives.

Further, the Council is extremely concerned that the forecast Westfield provided to the Siting Council in the 1984 Supplement is not the forecast and supply plan the Company actually uses for internal planning purposes. Through discovery, the Council obtained information that in some cases conflicted with information provided in the Supplement (e.g., conflicting sendout data for a peak day of 69 degree days). The Council cannot reconcile such conflicting information, although analysis of both sets of sendout data leads the Council to believe that Westfield can adequate supply the sendout requirements based on either set of data.

The data inconsistencies, however, raise the question as to whether Westfield has two planning frameworks -- an internal one actually used for planning resource dispatch, and an external one to fulfill Siting Council requirements. In fact, it is unclear whether two frameworks actually coexist or whether Westfield was unable to transform its internal framework and information into a format that complies with Siting Council rules and regulations.

In either case, the Siting Council expects companies to present forecast petitions which are consistent with internal planning information and processes, both in content and level of documentation available. Condition 3 addresses this concern.

VI. Order

The Council APPROVES the 1984 Supplement to the Second Long-Range Forecast of the City of Westfield Gas an Electric Light Department subject to Westfield's compliance with the following conditions in its next supplement, which is due on November 1, 1985.

1. That Westfield review its current source of weather data for consistency with historic data in Westfield and with data used by utilities serving neighboring communities. Westfield should justify the source of weather data it uses for the 1985 Supplement in the accompanying narrative.

2. That Westfield research, evaluate and report the findings on alternatives to its current design and normal year sendout forecast methodology, which is based on the most recent year's sendout data.

3. That Westfield, in its next filing, include its planned Daily Dispatch Log for 1985/86. The 1985 Supplement's sendout forecast should be consistent with the planned Daily Dispatch Log for 1985/86, and any remaining differences between the forecast and the Daily Dispatch Log should be explained and justified in the narrative accompanying the 1985 Supplement.

4. That Westfield research design year criteria and select an acceptable design year criteria, such as was used in Westfield's 1981 Forecast.

5. That Westfield file sendout data on interruptible sales on form G-4(A) instead of form G-4(B), and correctly file the G-22 forms.

6. That Westfield explain and document its knowledge of the community and use of judgement in adjusting average number of customers and load factors.

7. That Westfield provide a cost studies determining the level at which its MDQ for Tennessee should be set and the quantity of Bay State gas supplies it will need beginning in 1988-89.

8. That Westfield meet with the Council's staff before July 1, 1985 to discuss compliance with these conditions.

Carolyn E. Ramm, Esq.
Hearing Officer

On the Decision:
Calvin Young
Analyst

Unanimously APPROVED by the Energy Facilities Siting Council on May 23, 1985, by those members and designees present and voting: Chairperson Sharon M. Pollard (Secretary of Energy Resources), Sarah Wald (for Secretary of Consumer Affairs, Paula W. Gold); Stephen Roop (for Secretary of Environmental Affairs, James S. Hoyte); and Madeline Varitimos (Public Environmental Member).

5-30-85
Date

Sharon M. Pollard
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Eastern Utilities Associates for an Advisory Opinion Concerning the Subject Matter Jurisdiction of the Energy Facilities Siting Council	)	EFSC 82-33A

FINAL ADVISORY OPINION

Paul T. Gilrain, Esq.
Counsel

Charles B. McMillan
Executive Secretary

1. Introduction

Eastern Utilities Associates ("EUA"), an "electric company" as defined under M.G.L. c. 164, sec. 69G, under the jurisdiction of the Energy Facilities Siting Council ("EFSC" or "the Council"), petitioned the Council pursuant to 980 CMR part 7.02(10) for an advisory opinion as to the Council's jurisdiction concerning a proposed substation in the Fall River area. At its regularly scheduled meeting on November 22nd, 1982, the Council voted unanimously to grant said petition and directed the Council legal staff to prepare a tentative opinion on the subject.

2. Description of the Proposed Facility

EUA has proposed[1] to build a 115 kV/13.8 kV, 25/33/41 MVA substation and transformer on the west side of Sykes Road, in Fall River at the Fall River Industrial Park. The substation would tie in to the existing EUA 115 kV N-12 line at this location and step down the voltage to relieve pressure on the existing 23 kV system, to provide a more reliable supply of electricity to the area and continue EUA's progress towards a 13.8 kV system for the area. The proposed substation is part of an overall plan for improving electric service in northeastern Fall River; however, all new transmission lines which are being proposed in conjunction with the substation are under 69 kV capacity[2] and are, therefore, not under the jurisdiction of the EFSC. (M.G.L. c. 164, sec. 69G).

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1 See letter of Oct. 15, 1982 from John F. Lucey of Clarkin, Waldron, and Trucker, to Paul Gilrain, General Counsel, EFSC; and EUA Ex-1: Fall River Airport Industrial Part Expansion and its Effect on the 23 kv Distribution System, by Edward J. Krenzier, P.E. Distribution Planning Group. We make no determination herein as to the merits of this proposal. (Hereinafter "Krenzier.")

2. Krenzier, pp. 1-6, Figures 1-6.

3. Analysis of Jurisdiction

As is pertinent to this petition, a "facility" over which the Council has jurisdiction is defined as:

> "...(3) any ancillary structure including fuel storage facilities which is an integrated part of the operation of any electric generating unit or transmission line which is a facility..."
> (M.G.L. c. 164, sec. 69G (emphasis supplied)).

The statute, then, gives the Council appropriate jurisdiction over a substation which is an "integrated part of the operation" of a jurisdictional transmission line, that is, over 69 kV capacity and over one mile in length. The statute does not require that the associated generating facility or transmission facility be new. The materials submitted by the Company to the Council indicate that the proposed substation will be an integrated part of the existing 115 kV line:

> Since 115 kV lines are present at the center of the load in the industrial park and the proposed distribution circuits would be easily accessible, a substation here would be most beneficial.[3]

The pertinent regulation, 980 CMR 7.04(8)(1), requires a utility to file particular information "...(f)or each new facility to be located in Massachusetts and not otherwise approved or exempt." (emphasis added). Hence, this statutory reading would suggest that the proposed substation is a facility and that a full filing must be made.

It could be argued here that, since the 115 kV line has been in operation for several years, the new substation could not be an "integrated" part of its operation. But to the extent that the 115 kV line was installed to provide electric service to EUA customers, and to

* Krenzier, p. 6.

the extent that the new substation will improve the service delivery in an important way, we find that the new substation is integrated. The object of all statutory construction is to ascertain the true intent of the legislature from the words used. Lehan v. North Main Street Garage, 312 Mass. 547, 45 N.E.2d; 945, (1943). To ascertain that intent we will look to the purpose and not the letter, of the statute, for that is what controls with respect to its interpretation, Walsh v. Ogorzalek, 372 Mass 271, 301 N.E.2d; 1247, (1977) and we must construe the statute, if reasonably possible, to carry out that intent. Industrial Finance Corporation v. State Tax Commission 367 Mass. 360, 296 N.E.2d; 1, (1975). For these reasons, we find it unnecessary to derive an engineering definition of the term "integrated part of the operation," and rely instead on the submission of the company which indicates that this substation will "impact the whole distribution system" in a positive way.

An interpretation of Section 980 CMR part 7.04(8) 4 is also necessary to determine how existing regulatory requirements apply to the proposed substation. This section states that "new substations... which are associated with and constructed at the same time as a transmission line" are under EFSC jurisdiction. (emphasis added). If this regulation were to refer to a transmission line "which is a facility," as the statute does, one might reasonably conclude that there is no jurisdiction in this instance, since the only transmission lines proposed to be constructed by EUA are 13.8 kV, less than the EFSC statutory minimum. However, in interpreting the regulations of an agency in which is vested broad authority to effectuate the purposes of an act, "... the validity of the regulation promulgated thereunder will be sustained as long as it is 'reasonably related to the purposes of the enabling legislation.'" Levy v. Board of Registration and Discipline in Medicine, 378 Mass. 519, 392 N.E.2d; 1364, (1979) quoting from: Mourning v. Family Publications Service, Inc. 411 U.S. 356, 36 L.Ed.2d; 318, 93 S.Ct., 1652, (1973). We must, therefore, interpret the regulations as consistent with the legislative enactment if at all possible.

We therefore interpret 980 CMR 7.04(8)(4) in this case to mean what it says: that a substation "associated with and constructed at the same time" as any transmission line is subject to EFSC jurisdiction. Hence, the proposed EUA substation is subject to the jurisdiction of the EFSC under 980 CMR 7.04(8)(4).

Conclusion

Part 7.04(8)(1) is a broad expression of EFSC jurisdiction requiring information to be submitted with regard to any new facility being proposed by the utility. In its discretion, the Council then adopted regulations that specify a number of subsets of facilities for which it also requires filing information, in this case substations constructed at the same time as a transmission line. It also exempted from Council review a class of substations which are defined as, "...(iv) temporary placement of generating or substation facilities to be utilized for a period less than one year." 980 CMR part 7.04(8)(9). We conclude that the substation proposed by EUA is both a new facility as is meant in part 7.04(8)(1) and a new substation associated with and constructed at the same time as a transmission line (even though those lines are rated at 13.8 kV and are not facilities).[4] Hence, the proposed substation is

4 Krenzier, supra. pp. 1-6, Figures 1-6.

a facility pursuant to M.G.L. c. 164 sec. 69G and is subject to the filing requirements of 980 CMR parts 7.04(8)(1) and (4). The Company must comply with these requirements in its next supplement pursuant to 980 CMR part 7.05 or, if appropriate, an Occasional Supplement pursuant to 980 CMR part 7.05(3). No state agency may issue a construction permit until the Council determines that the proposed substation conforms to the most recently approved long-range forecast of supply filed by EUA.

Paul T. Gilrain /CBMcM

Paul T. Gilrain, Esq.
General Counsel

Charles B. McMillan

Charles B. McMillan
Executive Director

This Advisory Opinion was adopted by vote of the Energy Facilities Siting Council at its public meeting on Jnauary 24, 1983.
Voting in Favor of Adoption: Sharon M. Pollard, Chairperson; Bernice McIntyre (representing Secretary James Hoyte); Thomas Crowley; and Richard Croteau.
Voting Against Adoption: Dennis Brennan; Harit Majmudar.

Sharon M. Pollard

Sharon M. Pollard
Chairperson

Dated at Boston this 31st day of January, 1983.