DECISIONS AND ORDERS

MASSACHUSETTS ENERGY

FACILITIES SITING COUNCIL

VOLUME 7

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of the Boston Gas Company and Massachusetts LNG, Inc., for Approval of Their Second Joint Long-Range Forecast of Gas Resources and Requirements: 1981 through 1986	)	E.F.S.C. No. 81-25

FINAL DECISION

Paul T. Gilrain, Esq.
Hearing Officer
January 28, 1982

On the Decision:
John Hughes, Chief Economist
Martha Stukas, Senior Economist
Steve Buchsbaum, Analyst

LIST OF TABLES

TABLE OF CONTENTS

In the Matter of:

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

LIST OF EXHIBITS

Exhibits marked for identification:

EFSC 1	DPU 71 (DPU 555)
EFSC 2	Direct Testimony of J McKenna in DPU 555
EFSC 3-32	BGC-2-31 (DPU 555)
EFSC 33	Tenneco return volumes
EFSC 34	Inf. Return 6 from EFSC Inf. Req., set II
EFSC 35-44	Direct Testimony of W. Flaherty in DPU 555 and attendant exhibits
BGC 1	1981 Forecast

Record Requests:

EFSC 1-3	BGC Computer "model" forecast, present to March 31, 1982 assuming design weather: - assume existing DOMAC deliveries uniformly spread over 12 months. - DOMAC completes deliveries by Jan. 15, 1982, no extension of contract. - Same DOMAC deliveries plus BGC acceptance of DOMAC offer to extend.
EFSC 4	Extend computer "model" analysis in DPU 555 exhibit BGC 25 through 12 month period ending November 30, 1981.
EFSC 5, 6	Letters from BGC to DOMAC refusing offer to extend LNG deliveries through March 31, 1981.
EFSC 7	Updated cost figures on gas feedstocks.
EFSC 8	BGC precedent agreement with NESP
EFSC 9	Forecasted sendout of Boundary Gas supply, assuming on line November 1982.
EFSC 10	Impact of Boundary Gas Project on Cost of Gas to BGC.
EFSC 11	Contingency Plan filed with FERC
EFSC 12	New Propane contracts with Exxon, Petrolane, Sea-3
EFSC 13	Most recent data on BGC on conservation occuring within their system.

List of Exhibits (cont.)

EFSC 14	Most recent updated Mass S.A.V.E. report to BGC on energy audits.

Official Notice Taken:

1. Boundary Gas Petition to ERA and FERC, filed on Dec. 1980.

2. All testimony and exhibits in the record of DPU 555 concerning Boston Gas Company.

3. The filing of the New England States Pipeline project before FERC, dated October 9, 1981.

4. All three sets of the Company's answers to EFSC Staff information requests.

INTRODUCTORY NOTE

The Council understands that in some ways, this review must necessarily touch on some issues now pending before the Department of Public Utilities in DPU Docket No. 555, the investigation into the causes of apparent gas shortage during the winter of 1980-81. Neither the Council, nor its staff have attempted to conduct a review of that issue, and this decision should not be construed to absolve or condemn, in whole or in part, the Company for its actions during that period. We focus only on the Company's forecast, the methodology it uses to derive that forecast and how well it works to ensure the citizens of the Commonwealth that the Company will provide an adequate supply of energy, at the lowest possible cost, with the minimal impact on the environment.

I. INTRODUCTION

The Energy Facilities Siting Council hereby conditionally APPROVES in part, and REJECTS in part the Second Joint Long-Range Forecast of Gas Resources and Requirements of the Boston Gas Company, et al. The conditions of this Decision and Order are developed herein and outlined at the conclusion. The background and history of the proceedings are discussed in Section II. Section III defines the scope of the Council's review and Section IV, the standard of review. Section V contains the technical analysis of the Company's Second Forecast and the Council's determination as to whether or not the Forecast meets the intent of its regulations and statutory mandate. This analysis covers the Company's forecast of sendout requirements; the resources available for normal firm sendout; the resources for peak day sendout; the reliability and cost of heating season supplies, particularly LNG and propane; contingency planning and emergency procedures; and the need for additional facilities. Finally, Section VI contains conclusions and conditions pertaining to the next forecast filing by Boston Gas Company.

II. Background and History of the Proceedings

Boston Gas Company (the "Company" or "Boston Gas") is engaged in the sale of natural gas in the City of Boston and 73 other cities and towns in the Commonwealth. A breakdown of the Company's average number of firm customers is shown in Table 1:

Table 1

Boston Gas Company

Firm Customers by Class

	1979-80	1980-81
Residential with Gas Heating	212,562	227,900
Residential without Gas Heating	231,199	219,822
Commercial and Industrial, Firm	32,899	33,728

In addition, the Company is the sole supplier of gas to the Wakefield Municipal Gas Company and a number of, "interruptible" customers.[1] The actual total sendout for heating season and non-heating for the each last two years is shown in Table 2.

Massachusetts LNG, Inc. is a wholly-owned subsidiary of the Boston Gas Company and leases the two LNG tanks in Salem and Lynn on a long term basis. Boston Gas is, in turn, a wholly owned subsidiary of Eastern Gas and Fuel Associates ("Eastern"). Eastern also owns 36.8% of the outstanding common stock of Algonquin Energy, Inc., the holding

1 Sales to interruptible customers are subject either to a rate tariff filed with and approved by the Department of Public Utilities, or to the terms and conditions specified in a contract between the Company and the interruptible customer which is also filed with and approved by the DPU (Sales of most gas at the wholesale level is regulated by the FERC). The Company has stated that interruptible sales are made only as a residual, i.e., whenever there is gas available in excess of firm requirements. See discussion in part V(C).

Table 2*

Boston Gas Company

Actual Sendout by Class

	1979-1980		1980-81	
	Heating** Season	Non-Heating Season	Heating Season	Non-Heating Season
Residential with Gas Heat	19,854.4	9,032.3	23,511.5	9,409.7
Residential without Gas Heat	2,570.6	2,848.4	2,500.1	2,748.8
Commercial & Industrial, Firm	15,512.2	8,052.9	15,440.8	8,474.9
Wakefield Municipal Gas Co.	203.7	103.7	220.8	111.6
Interruptible	6,006.2	7,056.2	4,014.2	6,995.5
Wholesale Sales for Resale	25.6	931.7	118.5	337.7
Company Use & Losses	4,076.4	512.3	4,063.0	49.0
Total	40,217.3	20,550.1	45,736.0	20,785.0

* All figures in million cubic feet ("MMCF")

** The Heating season runs from November through March. The Non-Heating season runs from April through October. The data is thus compiled on a split-year basis.

company for Algonquin Gas Transmission Company ("AGT") which supplies slightly more than 50% of pipeline delivered natural gas to Boston Gas. In addition Boston Gas owns 7.52% of the outstanding stock of Boundary Gas, Incorporated, a close corporation formed to purchase imported natural gas from Canada. As will be discussed in Part V (B), (C), Tennessee Gas Transmission Co. ("TGT") will transport this gas to Boston Gas. Lastly AGT is a partner in the New England States Pipeline Co., a general partnership formed to import additional quantities of natural gas from Canada.[2] Boston Gas forecasts receipt of Canadian natural gas from both of these pipeline projects in the coming years. Figure No. 1 illustrates this corporate structure.

Figure 1

Eastern Gas and Fuel

Boston Gas — Algonquin Energy 36.8%

Mass LNG — Boundary Gas 7.52% — AGT NESP (one of four partners).

Boston Gas Company and Massachusetts LNG, Inc. filed their Second Long Range Forecast on April 15, 1981, pursuant to MGL Ch. 164, sec. 69I. The filing was preceeded by an exchange of correspondence between

---

2. Other partners are Texas Eastern New England, Inc.; NOVA, an Alberta Corporation; and, Transco-New England Pipeline Co.

Council Staff and the Company regarding the make up and significance of the Company's 1981 filing. The discussion focused on whether the 1981 filing was to be the fourth annual supplement to the Company's First Long Range Forecast, the actual Second Long Range Forecast, or a combination of these two as well as the first annual Supplement to the Second Long Range Forecast.

It may be helpful to review the filing history of the Company to explain this situation: The Company, pursuant to M.G.L. Ch. 164, Section 69I, filed its First Long Range Forecast in May 1976. Following this initial five-year forecast, a first Supplement was filed in December 1976, a second supplement was filed in December 1977, and a third Supplement was filed in October 1979. Up to and including the filing of the third Supplement, all of the Massachusetts gas companies followed a similar filing schedule. The fourth and final Supplement to the First Long Range Forecast was due October 1, 1980.[3] All of the Massachusetts gas companies except Boston Gas filed this fourth Supplement. All other companies were then informed by Administrative Bulletin 80-3 that because the Second Long Range Forecast filing date of December 31, 1980, specified in MGL Ch. 164 Section 69(I), was imminent, those companies would be granted an extention of the filing date to July 1, 1981 to give them adequate time to prepare their filing after receiving the decision on their fourth Supplement. Further, the Bulletin combined the Second Long Range Forecast with the first Supplement to that Forecast since that first Supplement would also be due in the summer of 1981.

---

3 EFSC Administration Bulletin 80-2.

This extension and combined filing of the Second Long Range Forecast and the first Supplement to that Forecast was granted to those companies which had filed the fourth and final Supplement to the First Long Range forecast due October 1980. Boston Gas was not in that category. Instead, Boston Gas was first allowed an extension of the October 1, 1980 filing date for the fourth Supplement to November 15, 1980.

The Council Staff then agreed to combine the Company's required fourth Supplement with the Second Long-Range Forecast due December 31, 1980. Finally, the Company was verbally granted an extension to April 1, 1981 for this combined filing. Thus, while for Boston Gas the fourth Supplement and Second Forecast were combined into one filing, for all other companies the Second Forecast and first Supplement thereto were combined.

Boston Gas has submitted to the Council for review its combined fourth annual supplement and Second Long Range Forecast. The Company, by letter dated March 3, 1981, requested further extension of its filing date to July 1, 1981; however, the then Executive Secretary to the Council, Elisabeth Ladd, by letter dated March 6, 1981, denied this request. In the March 3rd letter, the Company averred, in part, the following in support of its request:

> "... as a result of our own internal analysis of the data from last winter's experience which is just now beginning to emerge, we expect to have a very comprehensive sendout and supply strategy developed within the next two months. At the moment, however, the strategy is inchoate and we feel that both the interests of Boston Gas and those of the Council would be better served if our filing deadline were extended an additional three (3) months so as to enable our Forecast to reflect the significant developments in our supply and sendout strategy which are very likely to occur during this period."

Ms. Ladd's reply noted that the Company had received its last Council decision in July of 1980 and had had at least six months to prepare its filing. She also informed the Company that its forecast could be updated through the submittal of an Occasional Supplement, an amended forecast, or direct testimony in order to reflect whatever "sendout and supply strategies" were developed after the April 15th deadline.

The Company, however, did neither amend nor update its forecast during the seven months between submittal on April 15, 1981 and the adjudicatory hearing on November 30, 1981. The Company then challenged the Attorney General's right to intervene before the Council in this proceeding (see Appendix "A" for a complete discussion). Finally, the Council Staff entered into extensive discovery proceedings and two days of cross-examination of Company witnesses in order to ensure the accuracy and timeliness of information in the proceeding. As the hearing officer related to the Company, the Council will consider the information before us *in toto* as the forecast.[4]

Therefore, we base the analysis of the Boston Gas system sendout and supply which follows in subsequent sections on the totality of the information before us at the time of the close of hearings, December 1, 1981.

The Company filed its forecast on April 15, 1981. The Hearings Officer issued formal notice of Adjudicatory Proceeding on May 13, 1981. By letter of May 19th, 1981, the Attorney General moved to intervene in the instant proceeding. On May 29th, 1981, the Company filed a formal

4. In direct testimony on November 30, 1981, the Company submitted only its unrevised April 15th forecast (Exh. BGC-1). We note that Council regulations do not require the forecast to be updated prior to hearings.

Opposition to the Motion of the Attorney General. After briefing and oral argument, the Motion was allowed. The full text of that decision is contained in Appendix A to this decision and incorporated herein. After three sets of discovery questions by the Council Staff were presented to and answered by the Company, and after analysis by the Council Staff, a Notice of Public Hearing was published on October 19th, 1981. The Company, which had initially agreed to the hearing on November 8, 1981, later noted a conflict between this date and a U.S. Department of Transportation hearing on the operation of the Salem LNG tank and moved to change the hearing date to November 30, 1981. The motion was allowed by an Order dated November 5, 1981.

As is discussed in section V(D), infra, we were notified by the Company that Distrigas of Massachusetts, Corp. ("DOMAC"), the Company's primary supplier of LNG, would complete its contract deliveries by late January, 1982. On November 23rd, 1981, DOMAC made an oral motion to testify in the instant proceeding as a "participating person" pursuant to EFSC Rule 15.3. An Order setting a hearing on this motion for November 30, 1981 was issued on November 24, 1981.

At the hearing on November 30th, the DOMAC motion was allowed without objection. Both the Comapny and the Attorney General waived the seven day notice requirements and DOMAC was allowed to testify that morning. The Council Staff cross-examined DOMAC Manager of Marketing and Supply, Joseph Teves, and Boston Gas Vice-President of Gas Supply and Planning, Charles P. Buckley, on November 30th. On December 1st, 1981, the Council Staff cross-examined Walter Flaherty, Manager of Market Analysis and Rates for Boston Gas. The Attorney General did not present testimony or exhibits on cross-examination.

III. Scope of Review

The Long Range Forecast submitted by the Company must be measured against the requirements set forth in section 69I of Chapter 164 of the General Laws. That provision lays down a broad guideline for gas forecasts, mandating that each five year forecast accurately project the "...gas requirements of the individual company, and specifically, ... the gas sendout necessary to serve the projected firm customers, and the available supplies for the ensuing five years." (emphasis supplied).

Consistent with our general mandate, that is, to ensure "... a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost" MGL Ch. 164, secs. 69H, 69J, we focus our review on the reliability of gas supplies, as well as the adequacy and cost of those supplies. To do this we must look at three distinct areas of the Company's forecast and system plan for the five-year forecast period.

We must consider at the outset those agreements for gas supplies into which the Company has entered with pipeline companies, distributors of supplemented fuels and other gas companies, whether within or outside the jurisdiction of the Council, that will affect the ability of the Company to deliver gas to its firm customers. Such agreements take many forms: firm and "best efforts" contracts for pipeline gas, synthetic natural gas, feedstocks, or liquefied natural gas; contracts for the transportation of the gas to the Company's system; agreements for the use of storage and other gas facilities; and, also, informal exchanges of gas among local distribution companies, in the form of "swaps" or "off-system sales".

The second area into which we must inquire is the Company's forecast of gas requirements within its "market area" MGL Ch. 164, sec. 69I, 69J. This is perhaps the most familiar territory for the Council because of the focus on declining growth in per unit energy use during the past decade and the attendant problems this poses for forecasters. However, in the case of gas companies, it is the behavior of the individual customer, intertwined with the marketing practices of the Company, which is the key to an accurate forecast of gas sendout. Because of this, we cannot take a narrow view of the Company's "market area", since we must ensure that the needs of firm customers within the company's service area are not jeopardized by sales to non-firm customers and off-system sales. The Company must document such "non-firm" sales and show how such service is to be met while maintaining sufficient supply and capacity on its system to meet firm load under design conditions.

Lastly, we are required to review the Company's system, to ensure that sufficient sendout capacity is available to meet firm needs. Such an inquiry must consider both the sufficiency and the reliability of the system to meet annual customer needs under normal and design conditions, and during periods of peak demand.

But this review cannot be conducted in a vacuum. Just as we must be aware of, and give due consideration to the New England Power Pool in our review of an electric company's forecast, we must consider the overall flexibility of the regional gas infrastructure in order to accurately evaluate any gas forecast. In recent months, we have seen demonstrations of the informal gas "pooling" as a practical solution to certain supply problems. In January 1981, an almost unprecedented series of colder than design days coupled with an unexpected interruption in LNG deliveries, the failure of projected customer conservation to occur as well as many other factors under investigation at the Department of Public Utilities caused some gas companies to run precariously short of supplemental or "peak-shaving" fuels (e.g., LNG, Propane, Naptha-based SNG). The gas supply situation in the Commonwealth was seriously affected by this series of events, the supplies available to meet peak day requirements had to be supplemented by off-system additions of gas from neighboring and distant companies. In the instant case, both because of the relative size of the Company and because of its dependence on supplemental fuels to meet over 50% of its peak day requirements, our consideration of region-wide system impacts is also important to a meaningful forecast review.[5]

To conduct such a review is a complex task requiring the compilation and scrutiny of large amounts of data on a wide variety of subject matter and at different points in time. For instance, the inventory levels in storage tanks for supplemental fuels at the beginning of the heating season is a key determinant in assessing the ability of the Company to meet its firm heating season load under design conditions; yet, such a review could have a different significance if conducted in July. There is no guarantee that July inventory will not have to be sent out to meet load requirements in the Company's market area prior to the beginning of the heating season; therefore, the timing and reliability of supplemental fuels shipments and inventory levels are relevant to the forecast review. Similarly, interruptible load, which is priced at some percentage of the end-user's cost of alternate fuels,

---

5 Boston Gas accounts for 32% of annual sendout in Massachusetts and 40% of peak day requirements.

is to a large extent, price dependent. That is, if the price of gas exceeds or nears the end users cost of the alternative fuel, the Company may lose that customer and may not be able to either send out pipeline gas or store it in an efficient manner. This could decrease the Company's load factor and increase costs to firm customers. It might also have the effect of eliminating a planning "cushion" which now allows the Company to sell off excess gas in "warmer than design" winters. Because we must consider a supply plan forecast for a five-year horizon, information on gas rates, the decontrol of natural gas prices, and the foreign markets for supplemental fuels, especially LNG, is necessary for accurate long range projections.

The Council has the jurisdiction to review, evaluate and issue decisions on company long-range forecasts, and to permit new facilities and therefore supplies to be added to the individual systems. To do this, the Council exercises broad discretion in scrutinizing the forecasts and forecast assumptions that serve as a basis for the Company's decision making process. The Council will continue to exercise this extensive and thorough review consistent with its public mandate. Such thorough investigative actions are necessary to the review process and the authority to do so may be necessarily or reasonably inferred from the Council's enabling lesiglation, Chapter 164 sections 69H et seq. See: Grocery Manufacturers of America et al. v. Department of PUblic Health 393 N.E. 2d 881, 886-887, 1979 Mass Adv. Sh. _____, Levy v. Board of Registration and Discipline in Medicine 1979 Mass. Adv. Sh. 1857, 1862, 392 N.E. 2d 1036 (1979), Opinion of the Justices 368 Mass 381, 834-835, 33 N.E. 2d 368 (1975). Recourse to specific authorization is wholly unnecessary as such powers are shaped by the "organic statute taken as a whole." Grocery Mfrs. supra, at 886, Commonwealth v. Cerveny 1977 Mass Adv.Sh 1943, 1952, 367 N.E. 2d 802, 808 (1977). The Council must take such action because it is "...responsible for implementing the energy policies..." in its organic statute, and must seek "...to provide a necessary energy supply for the Commonwealth...". Further, the Council is empowered to ensure that necessary supplies of gas are provided to firm customers, "...at the lowest possible cost." MGL C. 164 sec. 69H. We hope that this clarification of the scope of the Council's review will eliminate confusion among parties and minimize future objections based on relevancy.

IV. Standard of Review

In determining whether the Company's forecast meets the requirements of Section 69H, the Council must apply the standards set forth in section 69J. That is, the Council shall approve the forecast, if it determines that: (1) "... all information relating to current activities, environmental impact, facilities agreements and energy policies as adopted by the Commonwealth is substantially accurate and complete.."; (2) "projections of... gas requirements and of the capabilities for existing and proposed facilities are based on substantially accurate historical information and reasonable statistical projection methods..."; (3) "...projections relating to service area, facility use and pooling or sharing arrangements are consistent with such forecasts of other companies subject to this chapter... and reasonable projections of activities of other companies in the New England area..."; and finally, (4) that the forecast is, "... consistent with the policies stated in section 69H to provide a necessary power supply for the Commonwealth, with a minimum impact on the environment at the lowest possible cost..." MGL C. 164 sec. 69J. (emphasis supplied) Although other criteria may apply to a proposed facility, these four standards are applied in this case. With these criteria in hand, we now will review the Long Range Forecast of Gas Resources and Requirements filed by the Boston Gas Company, et al.

V. Analysis of Boston Gas' Second Joint Long-Range Forecast of Gas Requirements and Resources

A. The Forecast of Sendout and Conservation

1. Background

In response to conditions imposed by the Council on the Company's 1977 Supplement, Boston Gas provided its first econometric study of customer usage patterns and motivations for customer conservation as part of its 1979 filing. The Company demonstrated a major commitment to analyzing the determinants of customer use and sendout requirements, evidenced by a willingness to collect demand-oriented data and to experiment with the use of econometric modeling techniques. As a result, the 1979 forecast was less dependent on traditional, largely supply-constrained methods of forecasting sendout. The traditional approach was based on such factors as gas supply and supplemental feedstock availability, the temperature responsiveness of new and existing load, load losses, and ability to meet design sendout conditions.

The Customer Use Study employed an econometric model which projected future firm demand as a function of the ratepayers' responsiveness to gas price, the prices of substitute fuels, regional macroeconomic conditions, and weather factors. As a companion to the model the Company developed a monitoring program to track the usage patterns of a sample of 80,000 residential heating and non-heating customers. This sample is larger than the total customer base of all but two other Massachusetts gas companies. The Company began compiling reports using this database in 1978 although data for this sample extends back to 1977. A similar program to monitor the usage of commercial and industrial customers was begun in 1980. More recently, the Company proposed to continue its study of customer usage by conducting an appliance saturation survey sometime in the near future.[6] In our decision approving the 1979 filing, we expressed our strong approval of the Company's progressive approach to forecasting sendout, despite our recognition that this method also resulted in a measure of uncertainty. We made it quite clear that the reservations and criticisms of the Company's model were of a constructive nature and were in no way intended to discourage the Company's initiatives. We are encouraged that the Company's forecasting staff has continued this project, although the role of the econometric model is diminished. However, as will be discussed in this section, we have serious concerns with the way in which the the 1981 forecast was developed.

2) Methodology[7]

The initial step taken by the Company to forecast sendout in 1979 was to normalize the firm sendout data from the previous heating season. Normalization removes the random effect of weather from the time-series

6. Tr. II, p. 43-44.
7. The Council's decision on the Company's 1979 Supplement contained a lengthy review of the methodology used by Boston Gas to forecast sendout; however, since the Company's present methodology for forecasting sendout is based on the 1979 filing, a summary of that method is here presented.

data. This was done by first calculating a monthly weather adjustment on a degree day basis. Sales were then adjusted by class, in order to determine the sensitivity of each class' load to changes in temperature. Normalized sales for each class were summed for a twelve month period to arrive at total annual normalized sales, which were used as the base year from which future sales would be projected. The base year in the 1979 forecast was the 1978-79 split-year.

The Company then applied the results of its Customer Use Study as the foundation for forecasting the incremental load growth for each class over the base year load. The results of this process were adjusted on the basis of the Company's judgement of its ability to meet forecasted demand. For example, it was the Company's judgement to reduce the load growth which was projected by this methodology during the first year of the forecast period. At that time, natural gas was substantially less expensive than oil, producing a surge in demand for new gas hookups. The Company determined that this demand was in excess of its ability to supply it in the short-run, and that it would have to expand the scale of its operations in subsequent years to meet this increased demand. The Company then increased the incremental growth rate in the latter years of the forecast period to reflect the time lag in satisfying this demand.

Secondly, the Company forecast the temperature sensitivity of future load losses and load gains. The Company's judgement concerning the temperature responsiveness of future load is reflected in its method for allocating net firm load gain into heating and non-heating use for each class of service. The Company estimated that ninety percent of net load gain in the residential heating and commercial/industrial sector would be temperature sensitive. Since net losses were expected in the residential non-heating class as a result of conversion of these customers to gas heat, all load loss in the residential non-heating sector was projected to be non-temperature sensitive.[8]

The Company then distributed the additional increment of temperature sensitive load for each class in proportion to the degree days which occured in the heating months. Non-heating load was assumed to occur throughout the year and was distributed evenly over twelve months. Total annual incremental load gain for the heating and non-heating seasons was then aggregated with the base year amount to arrive at the forecasted sendout requirements as displayed in forecast tables G-1 through G-3.[9]

The methodology used in the present forecast is similar to the aforementioned, traditional approach. Sales and sendout data for the 1979-80 period were normalized by calculating a weather adjustment for each month. This adjustment was equivalent to the amount of heating sales per degree day multiplied by the number of degree days in that month which were above or below normal.[10] Application of this weather adjustment to total sales data yielded total normalized sales for each class of service.

Estimation of load gain for the forecast period was the next step in the process. Whereas the Company relied on the results of its Customer Use Study as the basis for this estimation in its 1979

---

8. As can be seen in Table 3, *infra*, this actually represents a shift of existing non-heating, non-temperature sensitive customers through conversions to more volatile temperature sensitive gas heating load.
9. Exh. BGC-1, EFSC 79-25, Tables G-1, G-2, G-3.
10. See Section V(A)(2), *infra*, for definition of "normal".

Supplement, the present filing reverts to the traditional methods and sources of information for forecasting load gain. As in filings prior to 1979, the Company's judgement was based on recent sales history, customer survey data, anticipated availability of pipeline gas and supplemental feedstocks, and local economic factors. These factors considered the price of natural gas, both absolute and relative to the substitute fuels, and the general level of macroeconomic activity in the Boston area. The Company distributed the forecasted new load over the heating season. Gross load gain in terms of sales was then adjusted by a factor for Company use and unaccounted-for sendout, which was assumed to be six percent of total sendout. This sendout total was then distributed evenly over twelve months. Finally, expected gross load gain was adjusted downward by the anticipated amount of load loss and conservation. This summarizes the Company's methodology for forecasting sendout requirements.

The purpose of any model is to reflect reality accurately, albeit more simply, in order to explain and predict events. The events which are being modeled are represented by relationships between and among certain parameters. Judgements necessarily enter this process in the choice of parameters which are considered to be important enough to merit inclusion, and in the specification of the relationship among these factors. To the extent that important factors are omitted from the model, or relationships among these factors are ill-defined, the model's explanatory power is diminished. This results in a less accurate picture of future events.

In the case of a utility which must anticipate the sendout requirements of its customers, the risk associated with inaccurate forecasting can prove costly to the utility's customers and/or its stockholders. The ability to accurately forecast future needs allows a company to make investments and gas supply contracts more efficiently and, therefore, to pursue a "least cost" strategy for fulfilling its customers' and stockholders' needs. We are not authorized to prescribe sendout forecasting methodologies for gas companies.[11] As a result, we are precluded from imposing a specification of the relationships among variables which significantly affect sendout requirements. However, we will determine whether the sendout and forecast methodology and the Company's choice of such relationships are reviewable, appropriate, and accurate. In re NEGEA 6 DOMSC ___, EFSC 81-4 (1981), In re MMWEC, 5 DOMSC 53 (1981). Part IV, supra, MGL Ch. 164 sec. 69J.

The Boston Gas "model" of sendout requirements in the current forecast consists of identifying the following six factors which have been determined by the Company to be "significant" factors in the forecast of future sendout requirements. Listed by order of significance, they are:

"1. The future availability of gas and feedstock,

2. The Company's marketing policies,

3. The Company's projection of future conservation levels for new and existing customers,

4. The temperature responsive characteristics of existing firm load, future load losses and future load additions,

5. Weather factors, particularly temperature, and

11 M.G.L. Ch. 164 sec. 69J.

6. Other economic factors, such as the price of natural gas, both absolute and relative to its substitutes, local economic conditions, etc."[12]

The specification of the relationship of these six factors to future gas sendout consists only of the statement that the factors are listed in order of significance, i.e., the future availability of gas and feedstock is most significant in determining future sendout, and "other economic factors" are least significant among the six determinants. The choice of these six factors and whether, as specified by the Company, they are ordinally significant will now be discussed in the remainder of this section.

2.a The Availability of Gas Supplies as a Determinant of Demand

Boston Gas has identified the future availability of gas and feedstocks as having the most significant impact on future sendout requirements. The Company states that "...[t]his five-year forecast of firm sendout requirements is more a function of supply limitations than a function of demand resulting from the relative price advantage of gas over competing fuels."[13] The forecast views the future available supply as a constraint or a "given" and subsequently determines the amount of load growth which is compatible with the given resources.

This "supply-constrained" analysis is characteristic of past Company forecasts, although the 1979 Forecast appeared to be moving beyond it. As presented in the 1981 Forecast, there are at least three basic problems with it. First, by treating future available supply as the constraint, this approach apparently obviates the need to forecast demand. The danger in ignoring the impact of shifts in demand is that

---

12 Exh. BGC-1, p. 8.
13 Exh. BGC-1, p. 10.

it obscures the dynamics which may be occurring in the marketplace as customers adjust their consumption to changing conditions. Indeed, the need for accurate demand forecasting becomes even more critical in the case where supply is constrained, or fixed, in the short run. MGL Ch. 164 sec. 69J, Part IV (2), supra. This is exactly the situation the Company faced during the 1980-81 heating season, as a result of a number of factors which are presently under investigation at the Department of Public Utilities, which apparently included extreme weather conditions, limited supply due to the unavailability of Distrigas LNG, and consumption patterns which diverged from forecasted levels. The Company has acknowledged that intervening circumstances which were not reflected in the forecast of last winter's marginal sendout requirements, in part, contributed to its constrained supply situation.[14]

Secondly, the "supply-constrained" assessment appears to underestimate the impact of price fluctuations for natural gas and competing energy sources. The forecast states that the Company "...expects to be in a position, using various marketing policies, to sell the load that is shown to be available in this forecast."[15] But surely the Company is aware that the price of gas is increasing relative to alternate fuels, especially oil. Different decontrol scenarios may have a significant impact on the Company's ability to attain its marketing goals. Last winter's gas shortages have heightened customer awareness.

14 Exh. EFSC-2, p. 8. It should be noted that the Oct. 1979 filing forecasted a conservation figure of 2% and was approved by the Council on July 21, 1980. This projection proved to be roughly accurate, although the Company raised its projection to 6% incremental conservation before the start of the 1980-81 heating season.

15 Exh. BGC-1, p. 17.

Thirdly, the "supply-constrained" view tends to reinforce a short term, year to year, perspective. One of the major task of management is to procure more supplies. But the volatility and uncertainty of price, of foreign imports, of domestic and imported Supplementals, and the undisputed fact that domestic ("lower 48") supplies are diminishing, make a long-term view critical. Reliance on availability of supply as the most significant determinant of sendout is problematic over the forecast period.

The Company's witness stated that short-run forecasting of changes in customer usage and demand would not produce information which would be valuable to the Company for planning purposes, due to the extreme sensitivity of demand to weather factors.[16]

As the Company's Customer Use Study indicates, however, changing patterns in consumer behavior can change aggregate demand depending on a wide variety of factors, as well as weather, which predominates. Thus, for purposes of meeting fluctuating levels of demand with the most efficient supply mix available, it is essential to be able to predict demand in the short-run as accurately as possible.

We note that as a result of combination of circumstances which included a forecast of demand for the 1980-81 heating season,[17] which turned out be be inaccurate, extremely expensive emergency supplies of LNG had to be procured from Southern Energy. The total volume of LNG acquired form Southern Energy to meet Boston Gas' shortfall was 1176060 MMBTU.[18] In contrast, the average cost of planned peak-shaving supplemental fuels used by Boston Gas, was approximately half as

16 Tr. II, pp. 14-16, 18.
17 Testimony of John T. McKenna, Exh. EFSC-2, p. 3.
18 Exh. EFSC-2, p. 6-10

expensive. The Council does not hold the Company responsible for its inability to predict random events (e.g., abnormal weather, hurricanes in Algeria, etc); however, we must ensure that the Company can reasonably forecast the response of its customers when confronted with these events. While it can be argued that the cost of these emergency volumes, in part, represents a penalty cost to the stockholders and/or ratepayers for the Company's inability to identify and specify the meaningful determinants of its customer's sendout requirements last winter, we are not making that judgement here. We note that these issues are the subject of a current investigation by the Department of Public Utilities.[19] However, we are of the opinion that investment of even a fraction of the cost of these emergency supplies into developing a better forecasting capability could minimize the risk of incurring future penalty costs.

In short, Boston Gas' reliance on the amount of available supply as the most important determinant of senodut gives the Council little assistance in understanding how the Company obtains the most reliable and least costly resource mix. There is an inherent trade-off between the reliability of supply and the cost of these volumes. Since consumers have a not tangible method to express their preferences between the reliability and the cost of supply, the Company must attempt to estimate this trade-off. Boston Gas' response to the supply emergency last winter was to maintain reliability by incurring the expense of emergency supplies. In doing so, it assumed that customers would bear the cost of maintained service. We note that there are risks

19 Docket DPU 555.
20 Ch. 604, St. 1981 (1981 Supp.).

associated with this assumption, as evidenced by recent legislation.[20] This risk can be minimized in the future by a better understanding of the factors which determine customer demand. We recognize that our statutory mandate, i.e., to require the Company to accurately forecast the requirements of its ratepayers has its limits; however, we must ensure a least-cost, firm supply to meet those needs.[21] Part III, supra, at 14, Part IV (4), id.

2.b <u>Company Marketing Policies</u>

The prudence of the Company's marketing policies depends on the extent to which Boston Gas can effectively determine the level and end-use characteristics of load additions over the forecast period and beyond. The Company's marketing policies will always be a significant factor in determining sendout requirements.

In response to the events which transpired during the 1980-81 heating season, Boston Gas instituted a moratorium on expansion of service to new customers. This moratorium was to be in effect until November 1981, at which time it would be re-examined. During the course of the hearings, the Company announced that the moratorium would continue in effect until the experience of the current (1981-82) heating season could be evaluated.[22]

Prior to the institution of the moratorium on the expansion of service, the Company had planned an aggressive marketing policy, projecting the addition of 15,000 new residential heating customers in 1980 and 16,000 residential heating customers in 1981. Table 3 displays the

---

21 MGL Ch. 164 sec. 69H, 69I, 69J, see Part IV supra, at 14 and Part III, supra, at 10.

22 Tr. I, pp. 126-127.

Table 3

Boston Gas Company

Change in Average Number of Customers[23]

Years	Residential Heating	Residential Non-heating	Firm Commercial/ Industrial	Net Total
1978-79	2288	(2248)	40	80
1979-80	8906	(6239)	389	3056
1980-81	15338	(11377)	1000	4961
1981-82	1000	(285)	572	1287
1982-83	10300	(10037)	600	863
1983-84	10300	(10000)	600	900
1984-85	10300	(10000)	600	900
1985-86	10300	(10000)	600	900
	68732	(60186)	4401	12947

23 Figures for Residential Heating, Residential Non-heating, and Commercial/Industrial classes were calculated from Tables G-1, G-2, and G-3, respectively.

projections of customer additions and losses which were incorporated into the forecast as of November 30, 1981.

The Company's marketing policy must strike a balance between the future availability of supplies and the benefits realized by the public in converting from oil to gas. A policy decision must be made to determine whether new supply and/or conservation "supply" should displace at least part of the higher-priced supplemental gas used for existing firm customers, or should be used for purposes of market expansion, or in some combination.[24] Additional fixed costs of service and commodity costs of gas incurred as a result of market expansion will have price impacts on existing customers. If the additional load is temperature sensitive, which the forecast indicates it will be, customers may face increases in both marginal and average costs due to the generally higher costs of additional supplemental fuels.

The Company is forecasting a substantial increase in the average number of customers to which it will provide service. The correlation between the increase in the number of residential heating customers and the corresponding decrease in the number of residential non-heating customers reveals that the majority of space heat conversions will be by customers who now use gas only for cooking, hot water or other non-heating applications. Notably, the forecast states that these new and recently converted residential heating customers use more gas per degree day than do existing customers.[25]

This may be due to the fact that customers who converted to gas from oil heat experienced a substantial reduction in heating bills due to the lower price of gas relative to heating oil which has prevailed in recent years. Another possible explanation is that most customers who

24 This is especially relevant to the issue of Canadian pipeline imports, which will be discussed subsequently.

25 Exh. BGC-1, p. 15.

convert to gas heat already are part of the residential non-heating class; while an original gas heat customer might use gas only for space heating and not for appliances. Lastly, because of the high cost of money in recent years, most customers who are able to afford the cost of conversion, which usually entails the purchase of a new burner, will most likely be more affluent than existing customers, and on average, have larger dwelling space to heat.

This wide variety of possible explanations of the Company's data points out the need for the Company to further refine and disaggregate its data collection in order to be able to more accurately predict customer behavior. The failure of the Company to even separate conservation effects from load losses due to small business closings or from customers taking winter vacations further reduced the value of data on customer use on a per degree day basis. We understand the difficulties faced by the Company because of the lack of pre-embargo data (pre-1973); however, the Company must improve its methods of data collection if it is ever to accurately predict customer behavioral responses to such factors as price and weather.[26] The result of aggregating the separate usage patterns of existing and new/conversion customers makes it difficult to determine in fact if existing customers are conserving more than are conversion customers.

The Company has stated that it will either sell the conserved volumes of gas to new firm customers in the following years, or reduce its purchases of higher-priced gas, or both.[27] Yet, no specific plan

---

26 Tr. II, pp. 16-17.

27 Exh. BGC-1, p. 15.

has been enacted or proposed. In fact, the Company has increased its commitments to purchase higher-priced SNG and propane to meet projected load for the 1981-82 heating season. We are concerned about this lack of a firm policy in such an important area. The Company must serve its firm customers with the least costly, most efficient and reliable supply mix. To accomplish that goal, the Company should further disaggregate the data which it uses to forecast customer usage so as to determine more accurately the source of "conserved" volumes and the impact of each additional customer on the average cost of gas to existing customers and to the system. It should further specify the separate effects of market expansion on base rates and on the cost of gas adjustment portion of average gas costs. Of the many factors which the Company cites as having a significant role in last winter's supply shortage, customer conservation and consumption patterns were clearly within the Company's responsibility to forecast to the best of its ability.[28]

Lastly, Boston Gas' marketing strategies should be closely linked to its expectations regarding the impact of natural gas price decontrol.[29] The forecast assumes a continuation of real price increases in the order of 2 and 3 percent after the expected date of decontrol. Given the vast uncertainties surrounding decontrol, and the fact that decontrol will have a greater impact on the later years of the forecast, the Company's judgement is that it is better to assume a continuation of the present trend of real price increases:

---

28 Tr. II, p. 35, 41-42, Exh. EFSC-2, pp. 7-8.

29 Exh. EFSC-2, pp. 7-8.
Again, the Company's expert witness concurs with this.
Tr. II, p. 33.

> "We didn't have any other better information on which to base it. I don't know what the elasticities are going to be in 1985. So we decided to leave it at the rates we forecasted in the preceding years. But there is no question that the rates have changed and gas prices will go up in excess of what they do between now and 1984 and 1985 and 1986." Tr. II, p. 33.

We have acknowledged the uncertainty associated with price decontrol.[30] However, we feel that it would be prudent for the Company to forecast sendout and conservation using a range of assumptions about the timing and impact of decontrol. Not only could this assist the Council in making more informed decisions, but also, such scenarios could provide consumers who are weighing the investment in conversion to gas service with more reliable information on which to base their decisions. As the Company's own internal documents state: "If you're going to forecast anything you should forecast it often."[31] The Company is expected to explicitly document its assumptions regarding price decontrol in its next forecast, and address how these assumptions are incorporated into the Company's marketing strategies. (See: EFSC Rule 66.5).

2.c Conservation

In our decision on the Company's 1979 forecast Supplement, we conditioned our approval by requiring, among other things:

> "3. That the Company document in its next supplement how it projects the average use per residential heating customer is affected by forecasted conservation;
>
> 4. That the Company document in its next filing how its projection of the number of residential heating customers reflects forecasted conservation,".
>
> 4 DOMSC 50, 52 (1980)

Further, we discussed the rationale for our concerns at length,

30 4 DOMSC pp. 55-57

31 DPU 555, Exh. AG-59, p. 16.

Table 4
Boston Gas Company
Five-Year Forecast of Conservation by Customer Class
(FIRM ONLY)

Years	Residential heating	Residential Non-heating	Commercial/ Industrial
1981-82	.5%*	.5%	.5%
1982-83	1.5%	.5%	1.0%
1983-84	1.5%	.5%	1.0%
1984-85	1.5%	.5%	1.0%
1985-86	1.5%	.5%	1.0%

* Amended to reflect "0" conservation.

noting the need for "better integration of the components of their methodology", id. at 64, and that, "...if the energy policies of the Commonwealth are to be achieved, the Company must provide assistance by focusing its forecasting efforts on, and better explicating, the relationship between forecasted conservation and the projected number of customers." id. at 65. The Company's response to our concerns was to initially forecast incremental conservation as shown in Table 4. The table was accompanied by a three page narrative which not only failed to document the forecast, but also raises more concerns and doubts about the Company's methodology. Furthermore, the Company amended its forecast to show a level of zero conservation for the upcoming heating season.

The Company witness, Walter Flaherty, explained that the zero conservation projection was not the result of the forecast prepared by his division, but a "management decision".[32] During cross-examination at the DPU's investigation of last winter's gas shortage, Mr. Flaherty went into detail:

> "The numbers that finally appeared in the Siting Council (forecast) were almost a foregone conclusion, and a judgement that the upper management of the company made."[33]

Further, in response to a question concerning what the forecasting department had recommended to "upper management", Mr. Flaherty responded:

32 Tr. II, p. 21. The Council has termed this type of Forecast as "judgemental".

33 DPU 555, Tr. V. 35, p. 128.

> "...knowing that the price of gas would be increasing at a relatively rapid rate over the coming year and that economic conditions dictated that it certainly wouldn't be in the best shape, given the impact that MassSAVE will have and a number of other different programs that are coming on our system, we were looking at relatively high numbers, in the three to five percent range".[34]

As we have done in the past, we note the efforts made by the Company in data collection and forecasting. 4 DOMSC p. 50 et seq. However, we do not condone the actions of the Company in showing the Council only the end result of its forecasting process, especially when the underlying data and analysis were available. We therefore REJECT that portion of the Company's forecast which purports to satisfy Conditions 3 and 4 of our 1979 decision and direct the company to comply with the conditions in its next filing (see Condition 4, infra.), See Part IV(1)(2) supra, at p. 14. We will, however proceed with our analysis of the Company's sendout forecast as submitted on April 15th, including the forecast of zero incremental conservation.

The Company based the projected levels of conservation on its judgement that the incremental conservation achieved by measures such as lower thermostat settings has been maximized and will decline in significance during the forecast period. It is the Company's opinion that future conservation will require customers to make capital investment in measures such as weather stripping, insulation, storm windows, storm doors, etc. Although the Company expects additional conservation to occur during the forecast period, it believes that the rate of conservation will decrease significantly from previous years.

---

34 Id. at 130

However, other than its assertion that future conservation will only occur as a result of more permanent and capital intensive measures, the Company remains silent on the factors which it considered in its projections of customer conservation. The omission of price considerations is very problematic. We note that the Company's 1979 Customer Use Study considered the impact of the price of gas, both in real terms and relative to competing fuels, on customers' usage. The actual impact of price changes on demand was found to be significant in that Study, a finding comfortably consistent with economic theory. This theoretical conclusion is further supported by the experience of recent years.[35] (See Table 5).

In the three years for which the Company has actual data available, there is a distinct correlation between price increases and the level of incremental conservation which occurred. Yet the "forecasted" level of conservation in the current proceeding, regardless of which projection - .5% or 0% - is used, indicates that customer usage will be virtually insensitive to price changes, even one of such a magnitude as indicated (30%). (TR. II, p.21)

We can only assume that the "management decision" to forecast zero conservation for 1981-82 was related to the shortages of 1980-81. The Council must question the wisdom and reliability of using an abnormal course of events such as the past heating season, as a base assumption from which to project future trends. To revise the projected conservation levels on this basis suggests the factors that influenced sendout in an abnormal period (e.g., weather, price and customer usage,

35 Tr. II, at 21.

etc.) will be repeated. We can appreciate the management's desire to plan conservatively for the upcoming winter as a reaction to last winter; however, any planning judgements should be based on "accurate historical information" and "reasonable statistical projections methods".[36] History presumably comprises more than one year's experience. In future filings, the Company should present and document its conservation forecast in accordance with the Council's regulations, and state its level of confidence in that forecast.

We stated in our decision on the Company's 1979 Supplement: "The ability to forecast sendout accurately depends on forecasted conservation."[37] The <u>key</u> to forecasting conservation accurately is in forecasting usage. We do not criticize the Company for recognizing our limited statutory authority to require demand forecasts from gas utilities.[38] However, since customer usage is an integral element in the determination of sendout requirements, it behooves the company to seriously consider the <u>factors which influence customer usage in a forecast of sendout requirements</u>. Conservation is <u>one</u> outcome of a change in customer usage, so that the issue of conservation is a microcosm of the larger issue of customer usage. We expect these factor to be addressed in future filings.

We recently directed one company to consider factors in the evaluation of customer conservation which:

---

36 MGL Ch. 164, sec. 69J. The lack of documentation in the forecast prevents us from determining whether the Company's methods were accurate and reasonable. See also Part IV(2) supra, at 14.

37 4 DOMSC, at 64 (1980).

38 MGL Ch. 164, sec. 69 J.

Table 5
Boston Gas Company
Rate of Incremental Conservation Since 1978

	Incremental Residential Heating Conservation	% Change in Price from Previous Year
Actual 1978-79	2.5%	15-16%
Actual 1979-80	7%	23-25%
Actual 1980-81	2%	12-13%
Forecast 1981-82	0%*	30%

---

* Mr. Flaherty explained this during the hearing: "We never got around to computing what (the 1981-82 conservation forecast) would have been. We were planning prior to the 1980-81 winter, relatively high levels of conservation to occur during the balance of the 1980's but over the next few years. <u>And having seen a radical change from our forecast during the past heating season, we felt it prudent to change that method and the underlying assumptions on those forecasts and thus have adopted a zero conservation forecast for 1981-82</u>." <u>(see</u> Tr. II, p. 21-2). (Emphasis supplied).

"...should include, but not be limited to, behavioral methods of conservation (e.g. reducing thermostat settings) and conservation methods requiring capital expenditures (e.g. efficient water heaters, furnaces and appliances, and insulation) as well as whether the significance of these methods can be expected to increase or decrease over the forecast period."[39]

We note that the Company itself defines conservation as a change in customer usage patterns:

"... We are measuring changes in usage. It gets back to your definition of conservation. I am defining it as changes in consumption per degree day over time whether it would be related to just a change in the customer's living habits or having that customer install some kind of capital improvement."[40]

It is important to recognize the distinction between a change in customer use of appliances and improvement in the efficiency of those appliances. Both effects will create shifts in customer usage. Behavioral factors which should be considered include customer usage patterns such as the the frequency of use of an appliance, the intensity in which it is used, and the number of appliances or energy consuming applications.

As noted, the Company has stated that the majority of incremental benefits to be realized from behavioral shifts has been exhausted, and that future conservation potential depends on capital improvements.[41] Since capital improvements, like behavioral shifts, appear to us to be sensitive to price increases, and since the Company is forecasting price increases of up to 30% for 1981-82, we cannot understand why a conservation rate of zero, or even .5%, has been forecast.[42]

---

39 6 DOMSC ___, EFSC 80-29(1981), (Berkshire Gas Co.), p. 5.
40 Tr. II, p. 15.
41 Exh. BGC-1, p. 14.
42 The Company has testified that it views conservation as having both price-induced and non-price induced components, the latter including a public-spirited recognition for the need to reduce energy consumption. Tr. II at p. 29.

Additionally, in its failure to address the effect of price increases on customer usage, the Company neglects the impact of price increases on customer income.[43] For a customer whose income is fixed from one period to the next, an increase in the price of any product which the customer purchases will reduce that customer's net real income. In light of the magnitude of recent gas price increases, the assumption that customers will not respond to additional behavioral motivations to conserve is questionable.

The Company's underlying assumptions regarding these issues should be more fully explained and documented in its next filing. While the Council has previously described forecasts as "complex amalgams of art and science,"[44] it recommends against wandering too far into the realm of the abstract.

2.d. Temperature Responsive Characteristics of New and Existing Firm Loads

The Company's fourth determinant for developing its sendout projections is the temperature responsive characteristics of existing firm load and net future load additions. This has been discussed *supra*, and need not here be repeated.

2.e. Weather Factors

The Company has identified weather as having the most significant effect on the accuracy of the sendout forecast in the short-run. Because of the potentially critical impact of this inherently random factor, Boston Gas plans its supply to meet firm customer requirements

---

43 Mr. Flaherty testified that such information about the customer base would be indeed valuable. Tr. II, p. 45.

44 4 DOMSC at 61, EFSC 79-25, (1980).

for a design year.

The design year which Boston Gas uses for planning purposes contains 6300 degree days,[45] and is based on an analysis of weather data for the period 1923-1973 and represents a statistical probability of .059 (1 in 17).[46] The Company has experienced three years in the past 60 years in which the 6300 degree day design conditions have been exceeded. In addition to planning for a 6300 degree day design year, the Company includes in this year a number of "extremely cold" days which are interspersed throughout the heating season; specifically, it plans for 25 days with temperatures no greater than 20°F, or 45 degree days.[47] These 25 "extremely cold" days contain 1274 degree days, equivalent to 20 percent of the total design year degree days.

Over the 1923-73 period, the average or "normal" year has contained 5758 degree days. The past heating season, which consisted of 5819 degree days, was only slightly colder than normal in the aggregate. However, according to the Company's calculations, the period between September 1, 1980 and January 31, 1981 was 17 percent colder than normal. Rather than experiencing a random pattern of 25 extremely cold days throughout the heating season, the Company was confronted with a 30-day stretch of cold weather from December 20 to January 18, during which time the weather was 35 percent colder than normal, and 24 percent colder than design.[48]

---

45 A degree day is defined as follows: "For each degree that the mean temperature on a given day is below 65°F, the result is one degree day." (See: Testimony of J.T. McKenna, Exh. EFSC-2, p. 11).

46 Exh EFSC-2, p. 11.

47 Exh EFSC-2, p. 12.

48 Exh EFSC-2, p. 7.

The "design year" criteria appear at this time to be adequate for planning firm sendout requirements although we note that it is somewhat less conservative than other Massachusetts companies. We find that the design year criteria could have at least one potential weakness: it may be hazardous to rely on these assumptions for short term planning. For example, a planning problem could arise during periods of persistent and extreme cold weather, as occurred last winter during the 30-day period when "colder than design" conditions were prevalent, if the Company were to base its short term decision-making on the comparatively warmer design conditions. This would assume that the weather would revert to, at worst, design conditions. Such actions may tend to prolong the Company's ultimate decision to commence its "Emergency Load Curtailment Procedure"[49] and effectively reduce the valuable lead time which is necessary to secure emergency supplies. This is particularly important if other supply uncertainties exist.

2.f. Other Economic Factors

The Company lastly considers "other economic factors," in their forecast of future sendout requirements. As repeatedly evident in the above discussion and analysis, no substantive documentation was presented by the Company on exactly how such factors were incorporated into the forecast, if at all. It is our judgement that these factors do significantly determine future sendout and their omission is a serious

---

49 See Part V(E) *infra*, "Contingency Planning"

concern.

3. Assessment of the Company's Forecast Methodology and Documentation

The Company's documentation of its methodology for the sendout forecast is seriously inadequate. The narrative of the filing is lacking in substance, and instead consists of vague and general statements. As noted, the Company has listed its six major determinants of future sendout in order of significance. Yet, no mention is made as to how this ordering was developed, which criteria were used to determine the significance of the factors, or the means by which other possibly significant variables were omitted from the methodology. It specifies no relationship between these six factors and future sendout other than the assertion that the factors have a significant impact. Indeed, the Company does not even state whether the impact of the factors are positive or negative, or how the determinants may affect each other.

The vagueness of the Company's discussion of its methodology makes it inherently unreviewable. In re NEGEA 6 DOMSC ___, EFSC No. 81-5 (1981). The failure of the Company to state the criteria which were used to judge the significance of these factors results in a purely subjective and judgemental set of assumptions, and these assumptions are the basis for the determination of sendout. We have no evidence which suggests that any other decision-maker would devise the same ordering of factors or include the same set of determinants which the Company has presented, given access to the same information and experience. The Company's dependence on subjective judgements concerning the impact of these factors on future sendout does not permit duplication of the results of the forecast of sendout requirements. Therefore, the reliability of the Company's model for purposes of predicting future events, i.e. future sendout requirements, is highly suspect. Due to the unreviewability of the model, the Council has no basis on which to determine the appropriateness or accuracy of the sendout forecast, nor to approve it. Part IV (2) Supra, at 14.

Specifically, the Company's filing would be substantially improved by more rigorously addressing the requirements set forth in EFSC Regulations 66.5 (a) (ii), (iii), (iv), (v), 66.5(b)(i) - (vii) and 66.5(c). We expect the company to remedy this in its next filing. MGL Ch. 164 sec. 69J, Part III supra, at 10, Part IV(2) supra, at 14.

B. Resources for Normal Firm Sendout

Boston Gas has contract agreements with both Tennessee Gas Transmission Company (TGT) and Algonquin Gas Transmission Company (AGT) for the delivery of gas by pipeline on both an annual and seasonal basis.

The specifications for each purchase gas contract are shown on Table 6. The Company also has contracts for off-pipeline gas supplies, notably, Algerian LNG from Distrigas of Massachusetts Corporation and propane from Exxon at its terminal in Everett as of the close of hearings. In 1968, 99% of the Company's total sendout was pipeline gas purchased from Algonquin and the remaining 1% was propane/air. In the recent 1980-81 heating season, pipeline gas constituted 60% of total sendout, 28% was made up from supplemental supplies, and the final 12% was LNG.

This shift in resource mix was due to the interstate pipeline companies' suspension of new contracts because of their inability to acquire

50 Exh. EFSC-2, p. 15.
51 Exh. EFSC-2, pp. 15-16.

Table 6

Boston Gas Company

AGREEMENTS FOR PIPELINE GAS

Contract	Type of Agreement	Maximum Contract Period Volumes (MMCF)	Maximum Daily Quantity (MMCF)
TGT CD-6	Annual	24,308	95.9
AGT F-1	Annual	34,306	127.1
AGT WS-1	Seasonal	2,894	48.2
AGT SNG-1	Seasonal	1,844	12.2*

UNDERGROUND STORAGE AGREEMENTS

Agreement	Transportation	Annual Storage Quantity (MMCF)	Maximum Daily Withdrawal** (MMCF)
Algonquin STB	AGT	3,500 MMCF	31.8 MMCF
Honeoye Storage	TGT	800	7.3
Consolidated Natural Gas	TGT	102.7	0.9
Penn York	TGT	1,318***	7.4

* An additional 5 MMCF/day is also available for the 81/82 heating season (Tr. I, p. 78).

** "Best Efforts" except for Algonquin STB which is firm return up to MDQ

*** Penn York storage and related best efforts transportation is available in the amount of 876 MMCF during the 81-82 heating season.

d

additional, largely domestic, supplies and is indicative of the steadily declining levels of proven domestic natural gas reserves since the late '60s.

Physical constraints involving the use of propane/air and expanding peak-shaving requirements led to the need to diversify its supplemental supplies. Boston Gas built one of the first LNG facilities in the United States and was the first to import LNG. In 1973, the Company constructed a dual feedstock, substitute natural gas (SNG) plant in Everett, which is capable of using either propane or naphtha. In the same year, Boston Gas contracted with Algonquin for the purchase and delivery of additional SNG each year during the November 1 - March 31 heating season. This SNG is produced by Algonquin at its plant in Freetown, Massachusetts and is delivered by pipeline. Boston Gas has negotiated an arrangement with Algonquin which provides for an option during each heating season that allows the Company to reduce its contractural obligation by up to 50%. The Company is entitled to a maximum annual quantity of Algonquin SNG totalling 1844 BBTU.[52]

The Company's current contract with Distrigas was negotiated in 1977 and provides for annual deliveries of 13,746 BBTU. In addition to being available as a peak day resource (see <u>infra</u>,V(C)) the Company uses Distrigas LNG as a source of base load supply during the summer. This enables the Company to fill its own LNG storage tanks and to replenish underground storage outside the State.[53] The need to vaporize Distrigas LNG to meet the "take away" obligation in the Company's Distrigas contract may indirectly "force" interruptible sales if pipeline supplies

52 Exh. BGC-1, p. 18.
53 Exh. EFSC-2, pp. 19-20.

are adequate for sendout requirements and LNG inventories are at or near capacity. It is unclear to the Council precisely how interruptible sales impact Company operations and planning. It is our intent, as expressed in the Conditions of this Order, that the Company clarify this issue. Boston Gas' typical share of an Algerian shipment is about 1,000 BBTU, with shipments arriving approximately every 20 to 30 days. When a ship arrives, DOMAC tenders Boston Gas its share the next day. The Company is contractually obligated to remove half of its share of the shipment within 10 days after tender, (50 BBTU/day) and the remaining half at least one day before the arrival of the next ship. The disposition of this "take away" obligation depends on the season, weather, and inventory levels (i.e., weather during the recent past). Usually, however, Boston Gas is not obligated to reduce its inventories at DOMAC's Everett facilities below 643 MMCF accept on a best effort basis should a larger shipment be delivered.[54] Boston Gas presently has agreements with four companies for a total of 5279 MMCF of underground storage capacity in New York and Pennsylvania.[55] Pipeline Gas is stored during the summer months, to be used as needed during the heating season. Most of this gas has been deliverable on only a "best efforts" basis, though Algonquin transportation of available STB storage is firm up to MDQ (See Table 6). The Company is committed to further upgrading such storage and delivery to firm, subject to the abilities of the pipeline and storage companies.[56]

54 Tr. I, p. 77.

55 Exh. BGC-1, Table G-15.

56 Exh. BGC-1, pp. 20-21, also, see infra, V(C).

To meet projected sendout requirements later in the forecast period, the Company is planning to be an active participant in the Boundary Gas and New England States Pipeline projects. (See Table 7). The Boundary Project consists of 14 participating utilities that have created the entity Boundary Gas, Inc., and are arranging through it the purchase of up to 185 MMCF per day of pipeline gas from Trans Canada Pipeline Ltd. This gas will enter the United States via the Niagara Falls interconnection and will be delivered to the repurchasers' service areas under transportation agreements with Tennessee Gas Transmission Company. Boston Gas' share of the Boundary project is 7.52% or 4787 MMCF of gas annually. Originally anticipated to commence in 1982, Boundary deliveries are now expected no sooner than late 1983.[57] Boundary and Tennessee have applications pending before the Federal Energy Regulatory Commission ("FERC") and DOE's Economic Regulatory Administration ("ERA") for authority to import and transport the gas and to construct additional facilities necessary for such transportation. TransCanada also has an application pending before the Canadian National Energy Board ("NEB"). The cost of Boundary Gas will be included in the computation of the Company's cost of gas adjustment (CGA), the DPU's rolled-in pricing mechanism for gas distribution. Presently the Company estimates the average cost of gas with Boundary to be $4.32 per MCF compared to $4.13 without Boundary. Any changes in the Company's CGA resulting from the inclusion of the Boundary Gas costs will be applied uniformly to all existing firm use ratepayers.[58]

---

57 Tr. I, pp., 115-116.

58 EFSC Record Request ^10.

The Company also expects to purchase gas from the New England States Pipeline Project, a partnership among Algonquin Gas Transmission Company (Algonquin), Texas Eastern New England, Inc. (Texas Eastern), Transco-New England Pipeline Company(TRANSCO), and NOVA, an Alberta (Canada) corporation. Approximately 306 MMCF per day would be imported under a 15-year contract with Pan-Alberta Gas Ltd., to be split equally between Algonquin, Texas Eastern, and TRANSCO. Boston Gas has requested 28.5% (29 MMCF) of Algonquin's share. An underground storage service is expected to be developed with this project but details are as yet unavailable. This service would greatly enhance the flexibility of the supply in meeting firm needs. The project's in-service date is set for late 1984, but will require extensive regulatory review, particularly the siting of a 360 mile long pipeline.[59] The pipeline corridor is proposed to run from the Canadian border at Calais, Maine, southward to Burrillville, Rhode Island. Eastern Massachusetts would be completely transected and twenty cities and towns could be affected. While service on this pipeline will commence with deliveries of gas primarily from Alberta, it is anticipated that should Alaskan or Maritime (e.g., Sable Island) reserves become commercially accessible, these resources might also be transported into the region. Additional compression facilities would be required to accommodate the increased gas flow.

The history of New England utilities' dealings with Canadian imports has had mixed results. The export of energy from any foreign

---

59 Note that the Boundary Project requires only the upgrading of an existing pipeline corridor.

nation is necessarily subject to their plenary discretion.[60]

This is not meant to eclipse the overall excellent relationship that has historically existed among the Canadian provinces and New England States in any way.[61] It is meant to point out the very real, albeit different, risks of relying on imported energy. In a situation in which the consumer in the Commonwealth does not have recourse to the courts of the United States in order to redress his or her grievances, the risk of serious energy supply interruptions takes on new dimensions.

We have several related concerns with respect to how future gas resources are used for firm needs. As proven domestic gas reserves continue to decline, distribution companies such as Boston Gas will be forced to depend on increasingly more expensive supplies with greater associated risks, to meet future firm sendout requirements. Canadian

---

60 In one instance the New England Electric System had a contract to refine fuel oil in Quebec at the Golden Eagle refinery. During the embargo of 1973, the NEB refused to renew the monthly export license of the refinery of the NEES contract and, despite the fact that the crude was owned by NEES, NEES was unable to effect deliveries. NEES suffered a loss as a result.

A second instance was the more recent dispute over the cost of imported elecricity from New Brunswick Power Authority's ("NBPA") Colson Cove oil-fired unit. The NEB decided that the Canadian Government's oil price subsidy could continue to be passed through to Canadian customers of the NBPA, but that exported electricity would be billed as if the oil was not subsidized. This violated the express terms of the NBPA's contract with most New England utilities. NEES filed a complaint at the FERC, claiming that, if this were to be the case, the continuation of the imports would not be in the "public's interest". NBPA eventually settled the case in the face of a FERC ordered cut-off, and renegotiated the contract. NEES Annual Reports for 1973, 1974.
FERC Docket No. ER76-67B.

61 A good example of this was the expeditious approval of a propane export permit by the NEB, allowing Boston Gas to procure emergency supplies of LPG during last winter.

gas supplies are, afterall, imported supplies, and Canada reserves absolute rights to set prices and deliveries across its borders, subject to Federal approval. Additionally, to the extent that the price of gas increases, it may lose its competitiveness with other fuels. This could result in erosion of a company's customer base, leading to an increased proportion of inelastic, largely temperature-sensitive load. This will further increase costs to the remaining customers. Condition 2 of this Decision and Order, and Conditions 1, 5 and 6, in part, address the Council's concerns on these issues. See Part IV (2) Supra at 14.

C. Resources for Peak Day Sendout

While normal firm sendout refers to aggregate volumes of firm gas deliverable over some contract period, peak day sendout represents the maximum rate of firm delivery on a daily basis. Thus, this maximum rate is a physical constraint of the system's facilities: pipelines; compressors; LNG vaporizers, propane/air facilities; and, SNG plants. Table 8 itemizes the maximum daily quantities ("MDQs") which can be delivered pursuant to the Company's purchase gas contracts with Tennessee and Algonquin.

The Company operates propane/air facilities at 10 locations, capable of a maximum daily sendout of propane/air of 52.8 MMCF. It also operates 3 major LNG facilities located in Dorchester (Commercial Point), Lynn, and Salem. Additional peak day LNG vaporization is also available at Leominster, Webster, and Spencer by truck hookups. In all the total maximum daily LNG sendout from the 3 plants and 3 truck hookup locations is 202.9 MMCF. Through its contract with Distrigas, up to 66.6 MMCF/day of vaporized LNG is available from Distrigas' Everett facility. Finally, the Company operates its own SNG manufacturing

Table 8

BOSTON GAS COMPANY

Comparison of Resources and Requirements: Peak Day Sendout
(MMCF/Day)

Existing Resources:		Planned Usage Last Year 80/81	Actual Usage Last Year 80/81	Forecast Period 81/82	Forecast Period 85/86
Algonquin:	F-1	127.1	127.1	127.1	127.1
	ST-1	0	0	0	0
	WS-1	48.2	47.7	48.2	48.2
	SNG-1	12.2	12.2	17.2	12.2
	STB	0	0	10.0	29.7
Tennessee:	CD	96.0	89.3	96.0	96.0
	Storage	0	3.9	0	0
Propane		52.8	7.2	52.8	52.8
Vaporized LNG (DOMAC)		66.6	117.2	66.6	66.6
LNG Storage		202.9	167.5	202.9	202.9
SNG Manufacture		40.0	0	40.0	40.0
Planned Resources:					
Salem Vaporization					15.0
Tennessee Firm Storage Return					22.3
Algonquin Firm Storage Return					31.8
Boundary Gas					14.2
New England States Pipeline					9.3
Total		645.8	572.1	660.8	768.1
Forecasted Sendout Req'd			622	647	721
Degree Days - Design		73	73	73	73
Degree Days - Actual			61	--	--

Sources: Table G-23, Second Forecast (4/15/81); p. 77, Vol. I, Transcript.

facility, also in Everett, with a peak daily sendout of 40 MMCF/day.

Relative to many other gas distribution companies, Boston Gas has a very large winter peak because its predominantly heat-sensitive residential load is not balanced with heavy industrial baseload requirements. The Company's maximum day/minimum day firm sendout ratio is 10:1. This results in an increased relative need for supplemental gas supplies to meet winter demand and some degree of toleration for the inherent risks of this type of supply. We define supplemental as any resource which is not deliverable on a firm basis, 365 day a year, with due allowance for leap years. Last winter, the Company's total Maximum Daily Quantity of pipeline gas was capable of meeting the daily needs of its firm customers for up to 20 degree days, i.e., on any day in which the mean temperature was 45°F or higher. The next increments of demand that exceed the Company's MDQs are supplied with other, typically more expensive, supplemental resources: winter service gas, storage return, propane/air and SNG. Peak needs are then met with LNG, the Company's primary peak-shaving gas.[62]

The Company plans its resource mix to meet all the requirements of its firm customers for a "design" winter, as described, supra. This includes sufficient peak-shaving gas to adequately supply design conditions and includes 25 "extremely cold" days which are expected to be interspered in a "design" year. (An "extremely cold" day is any day with a mean temperature at or below 20°F, i.e, at least 45 degree days). The Company's peak design day requirements were based on 73 degree-days, representing a mean temperature of -8°F which was the lowest mean

---

62 Exh. BGC-1, p. 10.

temperature recorded in Boston since 1923. The average peak day degree days during the last 6 heating seasons was only 56 DD.

The Company's peak day sendout capability has improved considerably from last year. As indicated in Table 8, the Company has secured net increases in its maximum daily sendout capabilities from both pipeline and off-pipeline resources. Particularly notable is the commencement of firm redelivery of Algonquin STB (i.e., underground storage return) at an initial maximum daily rate of 10 MMCF, with an additional 20 MMCF available on a "best efforts" basis. It is anticipated that the full capacity (29.7 MMCF/day) will be deliverable on a firm basis by the 1982-83 heating season.[63] The significance of this upgrading of service, which previously had been entirely served on a "best efforts" basis, is evident by noting that on last winter's peak day (January 4th, 1981) best efforts volumes received amounted to only 11.7% of the maximum rate. Yet the comparable percentages for the previous three winters were 97.0%, 97.5% and 80.5%, respectively.[64] Thus, when winter storage gas was really needed such as under last winter's conditions, it was not available. The Company does not plan for the use of "best efforts" winter storage deliveries to meet peak day requirements.

In our most recent Boston Gas Decision and Order,[65] we approved two LNG vaporizers for the Company's Salem and Dorchester sites. The Salem LNG vaporizer had a proposed rated sendout capacity of 15 MMCF per day and the Dorchester LNG vaporizer, 62.5 MMCF per day. The need for these units was predicated on the Company's projected firm load growth -- particularly oil-to-gas conversions for customer space heating

63 Tr. I, pp. 93-94.
64 Response to Staff I.R., Set I, A-11C.
65 4 DOMSC 51, EFSC No. 79-25 (1980).

requirements. 4 DOMSC 50, 83 (1980). Such conversions, absent comparable increases in non-heat sensitive baseload requirements, tend to disproportionately increase peak day sendout requirements. However, peak day requirements are not extensive volumes and, the additional forecast peak day requirements themselves do not require that significant additional volumes be maintained in storage. Neither proposed vaporizer is presently operational but the Company's moratorium on conversions remains in effect. This effectively reduces last year's forecast growth and hence, no problem is posed by the delay in the installation of these new facilities. However, we are concerned that significant further delays may increase ultimate costs to the Company's ratepayers. Recent cost estimates, as required in Condition 5 in the last Boston Gas decision, show that the "preliminary" cost estimates for each facility have increased since originally proposed to the Council. The cost of the proposed unit at Commercial Point (Dorchester) in particular has escalated from approximately $800,000 to over $1 million.[66] The Company is evidently having second thoughts about the need for this facility, having excised it from their current supply forecast.

In addition to Algonquin STB, the Company's peak day resources for the 81/82 heating season have been further augmented with a higher daily take of Algonquin SNG, (See Table 8), and overall, the Company's near term peak day sendout capability appears quite adequate. Part III Supra, at 14. Planned peak day resources for the forecasted period (1981-1986), besides the proposed vaporizers at Salem, include

---

66 Rec. Req. EFSC,7.

additional firm storage return from both Algonquin and Tennessee, and firm gas supplies from the two joint projects for importing Canadian pipeline gas: Boundary Gas and the New England States Pipeline. Beginning in the 1982-83 heating season, the Company estimates that 7.8 MMCF per day of firm storage return will be available from Tennessee and that 22.3 MMCF per day will be similarly available during the remainder of the Forecast period.

The Company has an agreement with Algonquin for the purchase of 3500 MMCF of underground storage service with a maximum daily withdrawal rate of 31.8 MMCF. This service is firm up to MDQ. The Company has also executed agreements with both the Boundary Gas and NESP projects for purchases up to 14.2 MMCF/day and 42.7 MMCF/day respectively. Neither project is anticipated to commence firm deliveries until late in the forecast period.[67] TGP would provide firm transportation for the Boundary Gas supplies and AGT would make firm delivery of NESP gas.

In summary, the Company's peak day sendout capabilities appear adequate. Part IV (1), (2) supra, at 14. As indicated above, the Council is concerned that the Company's estimate of the firmness of Canadian gas imports may be unduly optimistic. We suggest that the Company be conservative in phasing in these volumes for expansion of its firm customer loads. Of perhaps greater concern with respect to peak day needs is the disposition of the facilities approved in EFSC 79-25. 4 DOMSC 50. In its next filing the Company must provide the Council

---

67 Tr. I, p. 116.

with a better explanation of the reasons for (1) the slippage of the on-line date for the Salem vaporization facility and (2) the apparent elimination of the proposed Dorchester LNG vaporizer from the Company's forecast of resources.[68]

D. The Reliability, Adequacy and Cost of Heating Season Supplies and Facilities

A true test of the Company's planning for meeting its projected firm sendout requirements is the overall quality of service during any given winter heating season. It is at that time that the system's customers face the greatest risks. Specifically, the Company must secure adequate and reliable gas resources at the least possible cost. It is not sufficient that the Company demonstrate the adequacy of peak day resources or total supplies available for annual or seasonal firm sendout. It must also show that maximum effort was expended to attain a least-cost resource mix. Part III, supra, at 14, Part IV (1) (2) (3) (4), id.

Table 9 shows the Company's estimated cost of firm gas by source for the twelve months ending June 1981 and recent projections for the 1981-82 heating season. It is evident that on a cost basis alone the Company should minimize any dependency on naptha-based SNG and LPG, usually the most expensive feedstock. We are aware that constraints exist that preclude the development of a reliable resource mix based solely on the marginal prices of feedstocks. Low cost pipeline supplies are limited by diminishing domestic reserve levels and fixed-size interstate pipeline and storage facilities. Most supplemental supplies

---

68 Exh. BGC-1, Table G-23.

Table 9

Boston Gas Company

ESTIMATED COST OF FIRM GAS BY SOURCE

Source	1980-81 Season ($/Mcf)	1981-92 Season ($/Mcf)
Natural Gas City Gate Purchases	$2.803	$3.55
Liquefied Nartural Gas	6.257	6.90
SNG Production	8.123	8.50
Purchased SNG	10.894	11.00
Underground Storage Gas	3.340	4.00
Liquefied Petroleum Gas	7.967	7.85
"Spot" LNG Purchases	15.000	--

Source: First set of Staff Information Requests, Response to Question 7; Tr. Vol. I, p. 148

are secured with long-term contracts that include "take-or-pay" provisions. There are also physical limitations on the amount of LPG that can be injected into any given point in the system resulting from chemical composition differentials.[69] Finally, the uncertainty associated with the timeliness of the delivery of Algerian LNG also poses certain problems in attempting to ensure adequate supplies while minimizing feedstock costs. Although all of these factors are fixed to some degree in the short run, the Company has a continuing responsibility to make adjustments over the long term that reduce system costs. This is a major point of concern. Part III, (1), (4), Supra at 14-15.

On November 19th, the Company sent a letter to the Council in which it stated that Boston Gas anticipated it "will receive no LNG shipments from Distrigas during a period running from mid-to-late January up through March 31, 1982." This letter had been prompted by the Council's Administrative Bulletin 81-3, issued on August 17th, which required gas companies to alert the Council immediately in the event of "any disruption in their supply plan as forecast and last approved by the Council as soon as a disruption is known to the company." Upon receipt of the Company's November 19th notice, there was concern that the Company's LNG stocks would again be tight for the second consecutive heating season. The Staff then contacted DOMAC and learned that the situation had been created by unanticipated, timely delivery of Algerian LNG. Since late last winter LNG shipments arrived at fairly regular

69 Exh. EFSC 2, p. 16.

intervals of 24 days.[70] DOMAC's 12-month contract period with its customers runs from April 1 through March 31.[71] It became apparent to the Company at some point that deliveries of the full contract volumes would be completed as early as January, 1982. This created at least the potential that, for a brief period, deliveries to DOMAC's customers would not occur. However, since DOMAC's 12-month contract period with Sonatrach begins in January of each year, continued deliveries through the end of March were thus assured after full contracted volumes had been received by the gas distribution companies. DOMAC offered this "excess" LNG to its customers in September. Only Boston Gas declined to commit itself for its pro rata share of the "additional" LNG.[72]

The issue before us is thus the prudence of the Company's decision not to avail itself of the additional supplies, particularly given the fact that these deliveries would be discontinued over a major portion of the then-pending heating season. It is clear from the record that the Company's decision taken by itself, will have no substantive impact on the level of LNG inventories maintained through the 81-82 heating season. In fact, had the remaining DOMAC commitments (as of November 30) been scheduled to be delivered uniformly throughout the rest of the heating season, reflecting, perhaps more closely, the attempted delivery terms in the Sonatrach contract, end-of-the-month LNG inventories would

---

70 The terms of DOMAC's agreement with Sonatrach specify that "seventeen (17) full cargoes of a ship with a capacity of approximately one hundred twenty five thousand (125,000) cubic meters" be delivered annually "on a firm 'take or pay' basis", totalling 1,900, 000 cubic meters plus or minus 5% at Sonatrach's option. Deliveries are to be spaced by approximately 20 days, but only on a "best-efforts" basis. Tr. 1, pp. 11-13.

71 Tr. 1, pp. 23-24.

72 Tr. I, pp. 17-20.

73 Exh .EFSC-2, pp. 64-65.

Table 10

Boston Gas Company

ESTIMATED "END-OF-MONTH" LNG INVENTORIES WITH DIFFERENT DELIVERY SCHEDULE ASSUMPTIONS FOR THE 1981-1982 HEATING SEASON

		NOV.	DEC.	JAN.	FEB.	MAR.
CASE I. DOMAC Deliveries Discontinued in Feb.	DOMAC INV. EOM	1,443	1,153	1,001	1,070	233
	BOSTON INV. EOM	4,260	3,677	2,871	1,902	1,364
	TOTAL INV. EOM	5,703	4,830	3,872	2,972	1,597
CASE II. Remaining Contract Volumes pro Rata Delivered Through March	DOMAC INV. EOM	1,443	944	578	554	164
	BOSTON INV. EOM	4,260	3,672	2,771	1,822	1,378
	TOTAL INV. EOM	5,703	4,616	3,349	2,376	1,542
CASE III. Excess Volumes Taken through March	DOMAC INV. EOM	1,443	1,153	801	1,341	910
	BOSTON INV. EOM	4,260	3,877	2,971	2,002	1,558
	TOTAL INV. EOM	5,703	5,030	3,772	3,343	2,468

Source: Staff Record Request

NOTE: EOM inventory levels are based on <u>design</u> year total sendout requirements.

be slightly less than as presently planned. This can be seen from Table 10 by comparing Case I inventory levels with Case II levels. The Council notes that this decision was made after the Company had already committed itself to storing an additional 600 MMCF of LNG in its inventory for the current winter. Finally, it should also be pointed out that Boston Gas plans to meet its design condition, winter sendout requirements assuming no DOMAC deliveries after its storage tanks have been replenished during the non-heating season. Hence, any shipments tendered after the heating season begins are presumed to be supplies in excess of total design year firm sendout requirements.

The above determination notwithstanding, we remain concerned over this matter and other issues surrounding the Company's dependency on Algerian LNG which need further clarification in the Company's next filing. The cost implications of using additional quantities of LNG to displace other higher cost supplementals need to be examined. And perhaps more critically, the actual performance of LNG deliveries needs to be related to the Company's storage, vaporization and liquefaction capabilities for meeting its firm sendout requirements. Ultimately, we must assess the adequacy of these facilities, as well as the need for additional supplemental feedstocks such as SNG or LPG, as part of our review of the Company's long-range supply plans. To this end we place a condition on this Decision and Order that the Company commence a formal study of the relative risks and costs of supply for its purchased LNG and other supplemental feedstocks, as defined therein, relating these risks to the Company's on-going determination of its optimal mix of gas resources and facilities. This forms the basis for Conditions 1 and 4 to this Decision and Order.

E. Contingency Planning

As a condition for the approval of the Boston Gas Company's 1979 Supplement, we ordered the Company

> "...to report to the Council in its next filing on its contingency plans to meet all projected load requirements in the event that the supply of Algerian LNG is no longer available (including efforts to secure additional resources)."
> 4 DOMSC 50, 53 (1980)

We found it necessary to condition the approval of the Supplement due to the strategic role of LNG as a peak-shaving supply, and the erratic nature of past LNG deliveries.[76] The combination of events which transpired during the 1980-81 heating season, exacerbated by the loss of a crucial shipment of Algerian LNG during a period of extremely cold weather, regrettably provided the Company with the perfect opportunity to test the viability of its contingency planning.

Boston Gas' contingency plan consists of a strategy for coping with a five-month cutoff of Algerian LNG, which is set forth in an information response to a FERC data request and a document entitled "Boston Gas Company: Emergency Load Curtailment Procedure," which had been filed with the DPU in 1977.[77]

Pursuant to the Council's condition, Boston Gas included a summary of the plan as outlined in its information response to the FERC. This summary discussed the measures which the Company would take in the event of a loss of the DOMAC supply beginning in November of any given year.

---

76 "Response to FERC Staff Data Request, Question 1-A, in CP-77-216 et al." (See, EFSC Record Request 11).

77 Exh. EFSC -2, Testimony of J.T. McKenna, BGC-27.

The Company contends that there would be no initial impact of a DOMAC interruption, since it is the Company's normal practice to fill its LNG storage prior to November. If filled to capacity, the Company would have a 45-day supply of storage volumes to meet firm peaking requirements under design conditions assuming consistent patterns in customer usage.

To supplement the withdrawal from storage, the Company's subsequent proposed course of action would be:

1. Purchase of additional liquid propane on the domestic and/ or world markets;
2. Purchase of LNG on the spot market;
3. Exchange of oil for LNG with Japanese electric utilities;
4. Purchase of emergency gas supplies from other non-affected utilities; and
5. Appeal to customers for thermostat reductions.

Before addressing each of the Company's options, the Company's initial assumption that LNG storage is full prior to November deserves some attention. The Council notes that two of the Company's LNG tanks, the Dorchester T-2 tank and the Salem tank, developed vapor leaks or the potential hazard of leakage prior to the 1980-81 heating season. Inventory levels in the Salem and Dorchester tanks in October 1980 were therefore capped at 746 BBTU and 796 BBTU, respectively, while the capacity of these tanks is 1000 BBTU and 1120 BBTU. It is unclear whether the Company bases its 45-day storage supply assertion on the design capacity or on the normal operating capacity of its storage facilities. We further take notice of the uncertain status of the Company's Salem

LNG tank for the 1982-83 heating season.[78] Given these uncertainties, we encourage the Company to clarify its assumptions regarding the surety of its storage supply at the start of the heating season. This is not intended to challenge the Company's normal operating procedure. We rather wish to ensure that the Company has the sufficient lead-times necessary to mobilize alternative plans in the event that vaporization from storage is constrained.

The Company's lack of liquefaction capacity sufficient to quickly fill its own tanks, [79] and the Company's admission that they do not have a specific deadline at which they must begin liquefaction or institute their contingency plans [80] are of some concern to us. We expect the Company to address these concerns in its next forecast by refining and further documenting this plan. This is Condition 5 of this Decision and Order.

The Company's five component contingencies will be discussed in sequence.

1. Purchase of Propane on the Domestic and/or World Markets

The Company is interconnected to the Exxon LP terminal at Everett, Mass.[81] Terminalling of additional shipped volumes of propane is provided for by the Company's long-term contract with Exxon for LP feedstock for the Boston Gas SNG facility. Additionally, the Company has a liquid propane-air (LPA) plant at its Everett facility which could

---

78 See: In re Boston Gas Co., DOT No.: CFP-1036-H (1981).

79 The Company can liquefy 6 MMCF/day at Dorchester and 7.35 MMCF/day in Lynn. (Exh. BGC-1, Table G-14)

80 Tr. 4, pp. 144-5.

81 Exxon has announced the closing of this terminal in 1982. The Company proposes either to deliver LPG to its SNG plant by truck or to purchase the Exxon facility. Tr. II, pp. 62-64.

be used in conjunction with its SNG plant to process propane. If operated at capacity, the LPA plant would be able to double the output of the SNG-LPA facility at Everett.[82] Boston Gas also owns eleven smaller satellite LPA plants which could be brought on line if required.[83] The Company believes that all of its LPA facilities are within manageable trucking proximity to Exxon and the other LP port facilities in the region (Petrolane in Providence, R.I., and Dorchester Sea-3 in Portsmouth, N.H., and Selkirk, N.Y.).

The success of this strategy hinges on the accessability of barged propane and the availability of trucks for hauling supplies from the terminal. During last winter's emergency, propane supplies were procured from Venezuela and transported on the barge "Massachusetts," which had been chartered by Coastal Cryogenics. This propane was then made available to Providence Gas Company, which utilized the supplies to make propane-air for its system and backed off of its pipeline take from Algonquin for Boston Gas' use. While we are encouraged by the apparent availability of propane on the world market, we are concerned about the competition for trucking services in the event that there is a region-wide need for this supplemental supply, as happened last winter. While the supply of trucks available to any individual company may be adequate during an emergency, there exists the potential for significant

---

82 Exh. BGC-1, Table G-14.

83 Id.

double-counting of the same trucking services on a regional level.[84] The Council encourages the Company to evaluate the reliability and availability of transportation in the event of such an emergency.

2. Purchases of LNG on the World Spot Market

The Company considers the markets of Algeria, Indonesia, Alaska, and Brunei as potential sources of spot market supplies of LNG. Logistically, it would attempt to terminal these supplies via the DOMAC facility, or through the Commercial Point (Dorchester, Mass.) facility, in smaller ships.

The Company's confidence in the existence of a world spot market may be overly optimistic. The availability of supplies in this market is neither assured nor predictable, given that world LNG supply is locked into long-term contracts.[85] Additionally, the plan is highly dependent on sufficient lead-times for negotiating arrangements, transportation, and necessary waivers. We note that although Boston Gas was on the brink of success in arranging a shipment of LNG from Indonesia, it was nearly the end of January before this agreement could be finalized. By that time, weather conditions had changed and the import application was denied by the ERA.[86] We encourage Boston Gas to pursue more firm commitments or letters of intent to facilitate

---

84 Significant time was lost by other gas utilities in procuring spot LPG deliveries during last winter's gas "crisis" because of the unavailability of sufficient trucking and difficulty incurred in suspending federal and state trucking regulations. DPU 555, Tr. Vol. 50, pp. 13-21.

85 The Council is mindful of current surplus capacity, See Tr. I, p. 13.

86 We note that the status of the import application was always in doubt because of the high price being charged by the Indonesian supplier.

such "spot" purchases in the event of an emergency. In addition, the Company should further revise its contingency plan by estimating the cost of spot market LNG so as to be in the best position to minimize the costs of supplemental fuels. We look forward to such a submittal in the next forecast supplement.

3. Exchange of oil for LNG from Japan

According to Boston Gas, approximately 60 percent of all LNG use in Japan is by electric utilities for power generation. Most of these utilities have dual-fuel capability allowing also for oil-fired generation. The Company proposes to purchase low sulphur oil and swap these volumes for Japanese supplies of LNG in the event of an emergency.

Although we applaud the resourcefulness of the Company in this regard we question the feasibility of this option. While the Company has correctly identified Japan as a heavy user of LNG, (indeed, Japan imports more LNG than does any other country), the Company does not address the national policy of Japan which is aimed towards a substantial reduction in its dependency on Middle Eastern oil from the current 73 percent to 50 percent by 1990.[87] Towards this end, Japan is following a course of diversification in its fuel mix and suppliers, having recently reached an agreement with Indonesia for the purchase of LNG priced at crude parity.[88] Japan's commitment to and success in reducing oil imports suggests that the national government would require substantial incentives to allow the import of oil supplies for the use of its electric utilities. Assuming that this exchange

---

87 Energy Users Report, March 12, 1981, p. 447.

88 Id.

would be acceptable to the government, the plan would require additional arrangements for transporting both the oil and LNG with a minimum disruption to production. Witnesses for DOMAC in this proceeding have testified that although the exchange is conceivable, the necessary approvals, contractual agreements, and transportation arrangements would likely require more than two weeks to complete.[89]

In light of these constraints, the Council requires further exploration and documentation of this proposal before it could be considered part of a reliable contingency plan. We therefore encourage the Company to pursue agreements with the Japanese government and electric utilities which could include, but not be limited to, letters of intent to take oil and supply LNG, with a specification of the terms of this arrangement and potential quantities involved, and a clearer definition of lead-times required to affect these transactions. This information should also be contained in the refined plan to be submitted in the next Supplement.

4. <u>Purchase of Emergency Supplies from Other Non-affected Utilities</u>

It is the common practice in the gas industry to plan supply requirements to meet design conditions. Since most utilities adhere to this practice, a certain "cushion" of supply exists which allows the whole system some flexibility in dispatching supplies. However, there is no formal regional dispatching mechanism. The success of this contingency depends on the collective planning of each individual

---

89 Tr. I, pp.16, we note this estimate does not include transit time from Japan to Boston.

utility. During the 1980-81 heating season, Boston Gas was able to avail itself of volumes of gas which other utilities maintained in reserve. In addition to Boston Gas, other Massachusetts utilities engaged in gas exchange agreements and off-system sales. However, Boston Gas is distinguished from other Massachusetts gas utilites by its relative size:

> "Our sheer size, coupled with the fact that we serve the largest urban area in New England and have a very high percentage of residential customers, differentiates us from many other gas distribution companies in the area."[90]

Boston Gas' size limits it from depending on other, smaller systems in the region for emergency gas supplies.

These issues becomes critical in the later years of the forecast period. The region's supply mix is shifting to an increasing amount of supplemental and imported supplies, with their associated higher risks and costs. At the same time, the customer base is expected to be comprised of a greater amount of high priority users, as residential customers convert to gas heat. The increase in peak day requirements, discussed supra, must be met with firm and reliable supplies, and volumes previously held in reserve may be increasingly called upon to meet future firm sendout requirements, deflating the supply "cushion". While we are encouraged by the apparent flexibility of the gas supply system, we are concerned about the impact of Boston Gas' requirements on regional supply contingencies. We also note that the same transportation contraints exist for this contingency as for the Company's previous strategies. These issues are expected to be

---

90 Exh. EFSC-2, p. 9.

addressed in the next filing. Conditions 4 and 5 directly relate to these issues.

5. Appeal to Customers for Thermostat Reductions

The Company states that "[t]he difference in supply requirements between a normal and design winter in Boston Gas' System translates into a 3° heating cut back per customer."[91] However, other than direct curtailment of service, this is not a variable over which the Company has predictable control. In a period in which natural gas is being marketed as a plentiful and reliable fuel, it may be difficult to convince customers that a shortage actually exists. Further, the tendency of some customers to turn their thermostats up during a prolonged cold snap casts doubt on this contingency option.[92] The Council hopes that customers will correctly perceive the emergency nature of any supply interruption, but it cautions the Company from relying on this source as a contingency.

F. The Need for New and Additional Facilities

The Company has indicated that it is only "in the very preliminary stages of considering a number of new facilities designed to meet the needs of its commercial, industrial, and residential customers during the approximately five (5) year period covered by this Forecast."[93] Pursuant to Rule 67.7, two such facilities have been identified. First, a recycle compressor at the Commercial Point LNG Facility would improve

---

91 Exh. BGC-1, p. 25.

92 At least one Boston T.V. weatherman was cautioning viewers to turn their thermostats up to avoid frozen pipes during a recent cold period in January, 1982.

93 Exh. BGC-1, p. 4.

the Company's ability to liquefy pipeline gas. Second, the Company anticipates the need for an additional LNG storage tank. A specific site has not yet been identified. The Company is also considering the acquisition of the so-called "Arlington Lateral", a 5.85 mile long, 10 inch diameter pipeline which runs in a northwesterly/southeasterly direction between the towns of Burlington and Arlington. The pipeline is presently owned by the Tennessee Gas Transmission Company and would provide Boston Gas with additional dispatching flexibiity in that part of its service territory. The Company would also have to construct facilities that interface with the New England States Pipeline Project when and if that project receives approval.

Given the nature of the Conditions attached to this Decision and Order, the Company is directed to use its analysis of the potential need for these facilities as a vehicle with which to fulfill the relevant requirements of this Order. (See Conditions 1, 4, and 6, *infra*.) In so doing, it is the Council's hope that the public will be better informed and ensured of a reliable and adequate gas supply at the lowest possible cost.

VI. Conclusions and Conditions

We must emphasize that, although Boston Gas has much work to do on its forecast of sendout requirements, the Company has made some strides towards accurate forecasting since its first Long Range Forecast filing. However, further progress in forecasting expertise must be matched by data collection over time. The present Boston Gas service territory was consolidated only in the early 1970's, and much of this data is unfortunately unavailable and unrecoverable today. We commend the Company for its current efforts in data collection and we anxiously await the compilation of more comprehensive and accurate data. This, in turn, should speed the development of a more systematic and better documented forecast methodology. We direct the Company, as it fulfills the requirements of this Order, to work with the Council Staff so as to expedite the resolution of our concerns and to better educate the Council and its Staff about the Company's operations and planning. We expect that such cooperation will be mutually beneficial. This is Condition 9.

In conclusion, we find the methodological basis for the Company's forecast of sendout requirements over the five-year statutory forecast period is inadequate in substance and in documentation. While the Company's gas supplies and resources appear to be sufficient for its immediate needs, we are concerned that the Company may have potentially committed itself to excess high priced supplies (e.g. additional Algonquin SNG for the 81-82 heating season only). Lacking a more systematic basis for determining Boston Gas customers' needs, we have no recourse but to suspect this. If true, the Council's least-cost mandate would be violated.

Accordingly, the Energy Facilities Siting Council hereby REJECTS the Company's methodology for forecasting sendout requirements and conditionally APPROVES the supply forecast subject to the qualifications stated herein. The Council requires a complete response to these concerns from the Company in its next filing, which shall be a combined First and Second Supplement to the Second Long-Range Forecast.[94]

---

94 We note for the record that the Company responded to each of the conditions affixed to the decision issued in EFSC 79-25. The sufficiency of those responses is dealt with in the text, *passim*.

Therefore, the Company is hereby ORDERED to comply with the following CONDITIONS in its next supplement, to be Due by July 1, 1982:

1. That the Company commence a formal study of the relative risks and costs of its purchased LNG, SNG, and propane, relating these risks to the Company's on-going determination of its optimal mix of supplemental resources;
2. That the Company demonstrate and document in its next Supplement to this Forecast why pipeline gas supplies from Canada should not, in part, be used to back out of more expensive supplemental fuels;
3. That the Company demonstrate empirically in its next Supplement to this Forecast its determination that "conservation gas" supplies be recycled as a firm resource for new customers, be used as a supplemental resource for its existing customer base, or be treated as some ratio of firm and supplemental resources, and how this determination will be reflected in the Company's marketing policies. Should the Company determine that the adequate completion of this effort must extend beyond the period of the filing date for the next Supplement, the Company must thoroughly document in that filing the scope of its intended efforts, the extent of its commitment to resources,and the estimated time track of the entire effort;
4. That the Company fully comply with Condition 3 of our 1979 Decision (4 DOMSC 51, 55);
5. That the Company assist the EFSC Staff in evaluating the tradeoffs between additional storage and the deliverability and security of supplemental resources, including propane, vaporized LNG and liquified LNG;

6. That the Company further develop and substantiate its "contingency plans" to meet projected load requirements in the event of a disruption of LNG supplies from Algeria, in view of the Council's determination herein;

7. That the Company document the precise relationship between interruptible sales and the determination of a least cost mix of resources to meet normal firm sendout needs, in particular, the extent of and reason for interruptible sales that are coincident to non-pipeline sendout, and how this relationship is anticipated to change, if at all, over the forecast period;

8. That the Company faithfully comply with EFSC Administrative Bulletin 82-1 (Attached as a Technical Appendix to this Decision and Order);

and,

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

The Energy Facilities Siting Council

Paul T. Gilrain, Esq.
Hearing Officer

on the decision:
John Hughes
Martha Stukas
Steven Buchsbaum

This Decision was approved by a vote of 6-1 by the Energy Facilities Siting Council at its meeting on March 8, 1982 by those members or their representatives present and voting.

Voting in favor: Bernice McIntyre, Esq., Richard Pierce, Noel Simpson, George Wislocki, Richard Croteau, and Dennis Brennan, Esq.

Voting Against: Margaret N. St. Clair, Esq.

Ineligible to vote: Harit Majmudar, Ganson Taggart

March 29, 1982
Date

Margaret N. St. Clair
Margaret N. St. Clair
Chairperson

APPENDIX A

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Boston Gas Co. and Massachusetts L.N.G., Inc. for Approval of a Long-Range Forecast of Gas Needs and Requirements	)	EFSC No. 81-25

INTERVENTION ISSUES

Boston Gas Company and Massachusetts L.N.G. ("Petitioner") jointly filed their second Long-Range Forecast ("forecast") with the Energy Facilities Siting Council ("Council") on April 15, 1981 pursuant to M.G.L. c. 164, sec. 69H and 980 CMR secs. 7.06, 7.07. The Council published a Notice of Intent to Conduct Session on Interventions on May 13, 1981 in response to a letter from the Massachusetts Attorney General's Office ("A.G.") indicating a desire to intervene in the instant proceeding.

The Attorney General filed a Motion to Intervene in the instant proceedings with the Council on May 22, 1981. On May 29th the Petitioner filed an Opposition to the Attorney General's Motion to Intervene. After discussion with Attorneys for the Petitioner and the Attorney General on May 29th, the parties agreed to a schedule for submittal of memoranda of Law on the Motion and Opposition. This schedule was formalized in the Procedural Order of the Council dated June 2, 1981. Petitioner filed a response to the Council on June 8, 1981 per agreement of the parties. The Attorney General submitted two letters in response, dated June 3, 1981 and June 9, 1981. Petitioner filed corrections to their initial brief by letter to the Council dated

June 10, 1981. Oral argument on the Motion and Opposition was heard on July 6, 1981.

Petitioner asserts that the A.G. should not be permitted to intervene in the instant proceedings because he is not expressly authorized to do so by statute and, in the alternative, that such participation would unnecessarily duplicate the efforts of the Council to regulate in the public interest pursuant to its statute. In addition, Petitioner asserts that the Motion to Intervene is deficient in that it fails to make the showings necessary pursuant to M.G.L. c. 30A and 980 CMR part. 2.152(2) which require a potential intervenor to state:

> "...the manner in which the petitioner is substantially and specifically affected by the proceeding, the contentions of the petitioner, the relief sought, the statutory or other authority therefore, the representative capacity, if any, in which the petitioner is brought, and the nature of the evidence or argument which petitioner will present..."

We will address these contentions in reverse order.

I. Petitioner correctly identifies the initial Motion to Intervene as deficient. By no reading of that one sentence document can we determine the interest of the A.G.; the nature of the evidence to be presented; how the A.G. will be "substantially and specifically affected," M.G.L. c. 30A sec. 10; the representative capacity of the A.G.; or most important, the contentions of the Petitioner. We were, and remain, sympathetic to the plight of the Petitioner in this regard. We ordered the Petitioner and the A.G. to submit briefs or memoranda on the issues in contention and scheduled oral argument at the conclusion of the briefing session. Petitioner submitted a short brief in support of their Opposition while the A.G. chose to submit two letters, dated

June 3 and June 9, 1981, in support of his Motion. In the former letter the A.G. responded that:

> "...This proceeding impacts the same interests of Boston Gas customers as those of Cape Cod Gas Company and Lowell Gas Company customers which are impacted by their respective company's forecast filing. Just as in the case of Cape Cod and Lowell, the customers of Boston Gas have interests in insuring the adequacy, accuracy, and reasonable cost of the Company's projected sendout and supply planning. It is the intent of the Attorney General, through discovery, cross-examination and briefing to insure the adequate representation of these gas customer interests."

Interestingly, the A.G. closes by voluntering to amend his "short form petition" if the Council wishes that he explain his interests in further detail. The offer is misdirected. The Council has a long and productive history of cooperation with the A.G. in adjudicatory proceedings. 3 DOMSC 110, 113-114; 6 DOMSC, EFSC No. 80-19, ORDER dated April 28, 1981, and we are fully cognizant of the role played by the A.G. as intervenor vis a vis M.G.L. c. 30A sec. 10. However, it would be unwise for the A.G. to assume such knowledge is held universally. When administrative action is taken in an adversarial proceeding, as in the instant case, basic constitutional rights affording adequacy of notice and opportunity to be heard must be respected. U.S. v. Wood 61 Fed. Supp. 175 (D.C. D.C. 1945). To determine if such notice is adequate, we are guided by the legislative definitions in M.G.L. c. 30A sec. 10 and our own interpretation. 980 CMR part 2.152 (2)(3). Petitioner's right to such notice is a basic constitutional right and should not be given such short shrift by the Commonwealth's chief law enforcement officer.

We are directed, however, to be guided by the Massachusetts Rules of Civil Procedure, M.G.L. c. 164 sec. 69J, c. 30A sec. 11(2), to be "practical" in allowing amendments to pleadings and the scheduling of proceedings, M.G.L. c. 30A sec. 11(1). In that all such procedural rules must be, "... construed to secure the just, speedy and inexpensive determination of every action..." M.R. Civ. Pro. Rule 1, we now read the combined submittal of the A.G. to date, including oral argument, to be sufficient and adequate notice to the Petitioner, meeting the requirements of M.G.L. c. 30A sec. 10 and 980 CMR. The A.G. has submitted: the manner in which he, representing the public as affected by the Company, is substantially and specifically affected by the present proceedings, A.G.'s letter of June 3, 1981 in support of his Motion; his authority to intervene, Motion to Intervene of the Attorney General; the nature of his argument, letters of June 3 and June 9, supra; and, his representative capacity, id. Pursuant to M.G.L. c. 30A sec. 11, we hold that a representation of the A.G.'s contentions and, if any, relief sought, is premature at this time but must be stated, "... as soon as practical." M.G.L. c. 30A sec. 11(1). See: Friedman v. Jablonski 358 NE 2d 994 (1976): Dioguardi v. Durning 139 F2d 774 (1944).

II. The next concern of the Petitioner is fear that somehow, the A.G. will perform the role assigned by statute to the Council, giving the A.G. "de facto jurisdiction" over the subject matter of the proceeding. To reach this conclusion, Petitioner states that:

> "To allow the Attorney General to appeal whatever eventual order the Council might issue would not only give the Attorney General de facto jurisdiction, but also give him a chance to second-guess the Council in matters in which the Attorney General has no legal interest. Intervention would ... allow the Attorney General to tell the Council how to run this and that subsequent proceedings..."
>
> Petitioner's Brief in Support of Opposition. p. 7

In its broadest sense, jurisdiction is the right and ability to apply law to a given situation. M.G.L. c. 164 sec. 69J delegates the jurisdiction over energy facility review and the review of Forecasts and Supplements to the Council. Section 69P allows that jurisdiction for appellate review of such decisions shall rest in the Supreme Judicial Court of the Commonwealth and sets forth that Court's standard of review.

We find no support in any arguments made by any party, nor in any precedent known to us, for the Petitioner's assertion in this regard and agree with the A.G.'s characterization of it as "specious." To the extent that intervention allows "the Attorney General to tell the Council how to run this ... proceeding," such advice will only be enforceable by the Supreme Judicial Court, on appeal, pursuant to the standards set forth in M.G.L. c. 164 sec. 69P. This is properly the role of the chief law enforcement officer of the Commonwealth, and we welcome it. Attorney General v. Board of Trustees of Boston Elev. Ry. 319 Mass. 642 (1946).

III. Lastly, Petitioner challenges the legal authority of the A.G. to intervene before this Council. Petitioner states in the opening sentence to their argument:

> "It is axiomatic that in order to act, the Attorney General must be statutorily empowered to do so."

Brief in Support, p. 3

Petitioner cites no case, constitutional provision or statute in support of such a broad restriction; the Attorney General does not argue the point in his submittals. We are, like the Attorney General, an agency charged with the care of the public's interest, albeit in a much narrower subject matter area; however, we cannot affort to luxuriously bypass a question which bears so directly on our fiduciary role.

The authority of the Attorney General is not only based in statutory enactments, but is found deeply rooted in the common law. In a challenge, by the Governor, to his authority to direct the course of litigation involving representation of a state agency pursuant to M.G.L. c. 12 sec. 3, the Supreme Court clarified the broad responsibility of the A.G.:

> "The Attorney General represents the Commonwealth as well as the Secretary, agency or department head who requests his appearance. G.L. c. 12 sec. 3. He also has a common law duty to represent the public interest. Attorney General v. Trustees of Boston Elev. Ry. 319 Mass. 642, 652 (1946)."

See also: Feeney v. Comm. 373 Mass. 359 (1977); Richardson, "The Office of the Attorney General: Continuity and Change," 53 Mass. L.Q. 5 (1968).

Such a common law duty survives and inures to the current Attorney General through the Massachusetts Constitution which adopted the common law as the legal fabric of the Commonwealth except where the legislature altered or abolished such law. Mass. Const. Pt. 2, Ch. 6, Art. 6. Further, it is an established rule that a statute is not be be construed so as to repeal the common law, unless the intent of the legislature is clearly to do so. New Bedford Standard Times v. Clerk of Third District Ct. of Bristol 1979 Mass. Adv. Sh., 515 (1979). Commonwealth v. Knapp 26 Mass. 496 (1838). We cannot discern even a hint of legislative intent to abrogate the common law duty of the A.G. to represent the public interest in sections 3 or 11E of chapter 12 of the General Laws, but find substantial and recent case law reenforceing the existence of such a duty. Secretary of A & F. supra; Comm. v. Feeney, supra; Attorney General v. Kenco Optics, Inc. 369 Mass. 412 (1976).

The duty of the Attorney General to represent the public interest is bolstered by yet another constitutional provision. Article 17 of the Articles of Amendment of the Constitutions Convention of 1853, allowed for the direct election of the Attorney General, given the appointing power back to the "supreme power," the people. Official Report of the Debates and Proceedings of the State Convention, 704 (1853). Through this amendment, the Attorney General's common law duties, so far as pertinent to the needs of the Commonwealth, become a direct delegation of authority from the ultimate source of sovereignty under our consitution, the people. Official Reports, supra; Commonwealth v. Kozlowski 238 Mass. 379 (1921).

The Final step in defining the scope of the power and duties of the Attorney General was the consolidation of all responsibilities for appearing on behalf of the Commonwealth in "all suits and other civil proceedings." Ch. 490 of the Acts of 1896. The Court in Secretary of Administration and Finance observed:

> "This statute dramatically changed the prior scheme, wherein the Attorney General appeared only in the Supreme Judicial Court and acted as advisory only, on request, in other tribunals. It required instead that the Attorney General represent the Commonwealth and department heads in all proceedings in whch the Commonwealth was a party or interested...
>
> ...Although it has undergone minor revisions, the statute governing the powers and duties of the Attorney General has remained in substance virtually unchanged since 1896. See G.L. c. 12, sec. 3. Thus, the Attorney General is currently mandated to "appear for the Commonwealth and for state departments, officers and commissions in all suits and other civil proceedings in which the Commonwealth is a party of interest, or in which the official acts and doings of said departments, officers and commissions are called in question, in all the courts of the Commonwealth." G.L. c. 12, sec. 3. (emphasis supplied).

Most recently, the legislature established a funding mechanism to allow the A.G. to intervene in any matter, "... involving the rates, charges, prices or tariffs of an electric, gas ... company doing business in the Commonwealth and subject to the jurisdiction of the Department of Public Utilities." St. 1973 c. 1224, sec. 2, 1976, 266 sec. 3. The intent of this legislation was to remedy a deficiency, perceived by the Governor and General Court, in the adversarial administrative process established for the regulation of public utilities. The chosen method of remedial action is to fund the A.G., through assessments against the utilities, and direct him to represent consumer interests in such adversarial regulatory proceedings. At the time of enactment of Ch. 12 sec. 11E, the Council did not exist (although it was soon to be created by St. 1973, c. 1232) and neither the legislature nor the A.G. had any experience with its operations.

Petitioner would have us interpret the case of the single phrase "involving rates, charges, prices or tariffs" (emphasis supplied) in this section to prohibit the A.G.'s intervention because, technically, the Council's actions "affects" rates but does not "involve" them. Petitioner's Brief at 4-5.

It is axiomatic that a remedial statute must not be given a "narrow, cramped reading" to defeat its purpose. U.S. v. Standard Oil 384 U.S. 224, 225-6 (1966); U.S. v. Esso 375 F^{2d} 621 (3rd Cir, 1967) annotation 16 L. ed. 2d, 256, 1259-60 (1966). Rather, such a remedial statute must be given a liberal construction to effectuate its purpose. U.S. v. Standard Oil supra; letter of the A.G. June 9, 1981 in support of his Motion. Since the intent of Cahpter 12, section 11E was to remedy deficiency in the adversarial process regulating public utilities, we decline to accept Petitioner's "narrow, cramped reading" of that section as precluding the A.G. from participating in the instant, or, any Council adjudicatory proceeding. The A.G. has the authority to participate before the Council and represent the public interest. Secretary of A & F supra; Comm. v. Feeney, supra; Richardson, supra; M.G.L. c. 12 sec. 3, 11D, 11E, and we now exercise our discretion to allow him to do so. Boston Edison v. D.P.U., 375 Mass. 1, 44 (1979). Since there is no need to reach the question of whether the A.G. may intervene before the Council as a matter of right, we decline to address that issue.

It is therefore ORDERED that:

1. The Attorney General's Motion to Intervene in the instant proceeding be ALLOWED;

2. The motion of petitioner to delay this proceeding until after their testimony in DPU Docket number 555 is granted;

3. That Petitioner respond to the requests of the Attorney General and Council Staff on or before September 7, 1981;

4. That, by agreement, the parties will meet in a Technical Session in order to clarify issues of interest at 10:00 A.M., August 25th, 1981 at the Council Chambers.

Energy Facilities Siting Council

Paul T. Gilrain
Chief Council

Dated at Boston this 6th day of August, 1981.

APPENDIX "B"

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council
ADMINISTRATIVE BULLETIN 82-1

UPDATES TO CERTAIN GAS FORMS AND TABLES

This Administrative Bulletin concerns timely updates of Tables G-22(B), G-23, and G-24.

All Gas companies are hereby required to update and refile Tables G-22(B), G-23, and G-24 specific to the pending heating season of each filing year. These updated forms and tables are due on or before November 5th, of each year and must represent the Company's best estimate of its available resources for the heating season beginning November 1. As per Administrative Bulletin 80-3, each Company normally files its Long-Range Forecast or Supplement on or before July 1. This order directs all Companies to refile the indicated forms and tables immediately preceeding each heating season so as to make available to the Council and the Public the most complete and accurate data pertaining to forecasted sendout and resources for that heating season. Should there be no substantive changes from the previous Forecast or Supplement, a Company need only so indicate, in writing, by said due date.

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Boston Edison Company for Approval of Its Second (1981-90) Forecast of Electric Power Needs and Requirements	)	EFSC 81-12

FINAL DECISION

Robert T. Smart, Jr. Esq.
Hearing Officer
March 2, 1982

On the Decision:
Jeffrey Brown
John Hughes
Ronald Lanoue

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

LIST OF EXHIBITS

Exhibit	Description
BE-1	Long-Range Forecast (Demand) 1981-90, Volume I.
BE-2	Long-Range Forecast (Supply) 1981-90, Volume II.
BE-3	Long-Range Forecast, 1981-90, Technical Appendix
BE-4	Direct Testimony of Paul Davis and Kathleen A. Kelly
BE-5A	Errata Sheet (8 pages)
BE-5B	EFSC Tables Revised May 1981 by Boston Edison
BE-6	Comparison of Alternative Energy and New Technology Adjustments (1 page)
BE-7	Potential Forecast Adjustment (1 page)
BE-8	Question S-12(a) and Response (1 page)
BE-9	Question S-14(c) and Response
BE-10	EFSC Question 8 and others and Boston Edison Responses
BE-11	Attorney General Information Requests P-1 and others and Boston Edison Responses
BE-12	NEPOOL Model Tables (2 pages)
BE-13	Boston Edison's Commercial/Industrial Questionnaire
BE-14	EFSC Information Requests S-1 through S-19 and Boston Edison Responses
BE-15	EFSC Information Requests 1-30 (Second Set) and Boston Edison Responses
BE-16	EFSC Conservation Grant Information Request and Boston Edison Company Response
BE-17	Efficient Use of Energy Boston Edison Company - Response to EFSC "Supply Matrix"
BE-18	Boston Edison Response, October 20, 1981, to EFSC Staff Analysis
BE-19	Status Reports 1-4, Regarding Coal Utilization at Mystic Station

Exhibit Number	Description
BE-20	Status Report 5, Regarding Coal Utilization at Mystic Station
AG-1	Testimony of Susan G. Geller
AG-S1	Attorney General Information Requests 1-25 and Responses by Boston Edison
EFSC-1	NEPOOL - Batelle "Model for Long-Range Forecasting of Electric Energy and Demand", Volume I
EFSC-2	NEPOOL - Batelle "Model for Long-Range Forecasting of Electric Energy and Demand", Volume II
EFSC-3	"NEPOOL Model Documentation Updates, Nos 1-45"
EFSC-4	Boston Edison Company, Long-Range Forecast of Electric Power Needs and Requirements, Annual Supplement I-C, 1979 and 1988, Volume I
EFSC-5	Boston Edison Company, Long-Range Forecast of Electric Power Needs and Requirements, Annual Supplement I-D, 1980 to 1989, Technical Appendix, May 1, 1980
EFSC-6	Staff Analysis of BECo Long-Range Demand Forecast, 1981 to 1990

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Boston Edison Company for Approval of Its Second (1981-90) Forecast of Electric Power Needs and Requirements)	EFSC 81-12

This Decision APPROVES the Second Forecast of the Boston Edison Company, subject to certain conditions. No new facilities were proposed for adjudication. The first section contains background information and a procedural history. The second section describes and reviews the demand forecast. It includes a review of the evolution of the Company's methodology since the First Forecast was filed in 1976. The third section evaluates the Company's supply plan. The fourth section contains the Order approving the Forecast and conditions thereto.

I. BACKGROUND AND PROCEDURAL HISTORY

Boston Edison Company, an investor-owned utility, supplies electrical energy to 40 cities and towns in the Greater Boston area. Its annual electrical sales, 9,265 millon kwh in 1980, represent 28% of total annual electrical sales in Massachusetts.[1] Because Boston Edison's service territory is largely urban, an unusually high proportion (43%) of its total annual sales are to the commercial sector, and it experiences higher peak demand for electricity in the summer than in the winter.

---

1 Rounded figures, Boston Edison's 1980 filing with the Massachusetts Department of Public Utilities. Sales for resale are excluded.

A. Proceedings in 1978, 1979, 1980

Boston Edison last received a full decision from the Energy Facilities Siting Council on an annual filing on October 18, 1978. In that decision, EFSC 78-12, 2 DOMSC 112, the Company's Second Annual Supplement to its First Forecast was approved, subject to numerous conditions that were to be addressed in future filings.

Proceedings on Boston Edison's 1979 and 1980 filings (the Third and Fourth Annual Supplements to its First Annual Forecast, respectively), were never completed. The Third Annual Supplement, EFSC 79-12, was filed on April 2, 1979. Hearings on that filing were suspended by Procedural Order of the Hearing Officer, Dennis J. LaCroix, Esq., on March 4, 1980. The parties and the Council agreed, after extensive discovery and several conferences between the parties, to suspend proceedings and to close the official record on EFSC 79-12 because it was felt that Boston Edison was being unfairly burdened with a defense of the NEPOOL Model,[2] which is used by a number of New England and Massachusetts utilities. In addition, the Company's Fourth Annual Supplement was nearly ready for filing. Part of the Fourth Annual Supplement was filed May 2, 1980, the balance on August 8, 1980. Review of that Fourth Supplement, EFSC 80-12, was suspended (again after extensive discovery and a number of conferences) by Hearing Officer Robert T. Smart Jr., Esq's Procedural Order, dated December 2, 1980. The suspension of EFSC 80-12 was agreed to by the parties so that review of the Second Annual Forecast (the current proceeding, EFSC 81-12) would

---

2 The use of the NEPOOL model by the Massachusetts electric companies was later examined by the Council in a set of consolidated hearings rather than in the course of individual company proceedings. See EFSC Docket 80-8.

not be delayed.

B. The Current Proceeding

The Hearing Officer took official notice of Boston Edison's Third and Fourth Annual Supplements during the hearings on the Second Forecast, EFSC Docket 81-12 (the current proceeding). While the reviews of those two filings were never completed, the discovery and analysis which took place in them has been quite helpful to the Staff in its review of the Second Forecast.

Boston Edison filed its Second Forecast in three parts. Volume I (demand) was filed in December 1980, the Technical Appendix to Volume I in January 1981, and Volume II (supply) on April 1, 1981. The Company gave proper notice to the public of the adjudicatory proceedings by publication and posting at city and town halls within its service territory. The initial pre-hearing conference, held on January 23, 1981, was attended by the Attorney General, the Conservation Law Foundation, CCPAX, and two residents of Walpole.[3] Only the Attorney General intervened.

The Hearing Officer divided the review of the Company's forecast into two parts, with the assent of the parties. The "demand" hearings were held on May 27th and June 2nd, the "supply" hearings on November 18, 1981. This was done because the Staff wished to give the Company some "feedback" on its demand methodology as early as possible, to assist and guide its forecasting department in preparing its own

---

3 These residents were interested only in Boston Edison's Walpole to Needham 345 Kv transmission line, which has been the subject of controversy for several years, but which was approved by the Siting Council on December 6, 1978, 3 DOMSC 44 (need and site), and on September 18, 1979, 3 DOMSC 81 (construction).

internal forecast, and because the Company had filed its "demand-side" documents four months earlier than the "supply-side" documents.

Boston Edison's direct case on "demand" was presented in Volume I and the Technical Appendix, and through the testimony of Paul Davis and Kathleen Kelly, both from the Company's Forecasting and Load Research Division. These witnesses were cross-examined by Alan D. Mandl, Esq. of the Attorney General's office and Jeffrey Brown of the EFSC Staff. The Staff prepared an "Analysis of the Boston Edison Company's Long-Range Demand Forecast 1981-1990" and sent it to the Company on July 17, 1981. This paper was written primarily by Mr. Brown and Ms. Bos, staff analysts. It compared Boston Edison's First Forecast (1976-1985) to the Second Forecast (1981-1990) in terms of growth rates, methodologies and assumptions. It offered a critique of nine parts of the forecast methodology: demographics, the price forecast, price elasticities, the residential, commercial, and industrial class forecasts, conservation and alternatives, and the peak load forecast. No response was offered by the Attorney General. Paul Davis and his staff prepared the Company's response, which was filed on October 20, 1981. He spelled out areas of agreement and disagreement with the Staff's analysis. This dialogue between the Staff and the Company was continued at a technical session held on October 29, 1981. Both the Staff analysis and the Company's response are part of the record in this proceeding.

Susan Geller from the Attorney General's office testified at the "demand" hearings, and was cross-examined by William S. Stowe, Esq. of Boston Edison and Jeff Brown of the EFSC Staff. She offered criticism of the Company's forecasting methodology.

The Company's "supply" case was presented in Volume II of the Forecast. Cameron H. Daley, Superintendent of Boston Edison's Engineering, Research and Planning Department, testified briefly on direct examination. He sponsored Volume II, and noted two principal changes: the cancellation on September 29, 1981, of the proposed nuclear unit Pilgrim Unit Number 2, and the signing of a contract[4] with the New Brunswick Electric Power Commission for the purchase of 100 megawatts of Point Lepreau Unit Number 1. Mr. Daley was cross-examined extensively by staff members Ronald A. Lanoue and John Hughes.

The staff's questions were directed primarily in the following areas: impacts of the Pilgrim II cancellation, coal conversion decision schedule, load management, conservation, renewable resources, conservation grant program, importing of Canadian power, purchase of shares of Millstone III and Seabrook I and II, and Edison's commercial sector.

Alan D. Mandl, Esq. notified the Hearing Officer on the morning of the "supply" hearing that the Attorney General would not be involved any further in this proceeding. Consequently, he did not attend the hearing and did not submit any written materials. The Company, for its part, on December 2, 1981 submitted a brief in which it requested approval of its Second Forecast.

---

4 The Council notes the recent action by the Massachusetts Department of Public Utilities in connection with this purchase. Boston Edison requested an advisory opinion from the Department on July 10, 1981. Commissioners Jon N. Bonsall and George R. Sprague, in an opinion letter dated July 31, 1981, found that "the proposed purchase of an entitlement in Point Lepreau Unit No. 1 is reasonable" and that "all costs to be incurred by the Company pursuant to the contract including both fixed charges and operating costs are recoverable by the Company under G.L. c. 164, sec. 94G".

One additional area of interest should be discussed in this introductory section. That is the possibility of conversion to coal of some of Boston Edison's oil-fired units. After Governor King's announcement of a "Plan to Stabilize Utility Costs" and the Siting Council's promulgation of Administrative Bulletin 81-1, both in March, 1981, Boston Edison submitted a statement detailing some of its problems in converting Mystic Units 4-7 and New Boston Units 1 and 2 to coal. (See Boston Edison's report dated May 1, 1981, submitted with letters to Governor King and Secretary Fitzpatrick on May 4th). In view of the high degree of interest in coal conversion as a means of reducing or stabilizing costs to ratepayers, the Hearing Officer issued an Order on May 15, 1981 that the Company publish a new Notice of this Adjudicatory Proceeding. This Notice stated that the Council would analyze the conversion of Boston Edison's oil-fired units to coal in its pending supply-side hearings. The purpose of the Notice was to give additional parties the opportunity to participate, given the expanded scope of the proceedings. Boston Edison refused to publish the Notice. At successive Council meetings on June 22, 1981 and July 20, 1981, the Company argued that it had just begun to study the feasibility of coal conversion, and that adjudication of the coal conversion issue as part of the review of the Second Forecast would be premature. The Council accepted this argument, the Company agreed to file monthly status reports detailing its progress in determining the feasibility of conversion of the Mystic and New Boston units, and the Order of Notice was withdrawn. See the Hearing Officer's Procedural Order dated July 21, 1981. Accordingly, this Decision does not purport to decide the merits of the coal conversion issue.[5] A determination of the limits of Council jurisdiction over conversion of the Mystic and New Boston stations will not be made until the matter is sufficiently ripe.

5. The Conservation Law Foundation (CLF) petitioned to intervene on July 15, 1981, citing an interest in "analyzing in depth the technical and economic feasibility of burning coal at existing oil-fired plants". It expressed concerns about the effects of increased sulfur dioxide emissions and fugitive dust on air quality, and about ash disposal problems associated with the use of coal. CLF withdrew its Petition once it learned that the issue was not going to be adjudicated in this proceeding.

II. ANALYSIS OF THE DEMAND FORECAST

A. Introduction

No forecast is perfect and free from uncertainty. The development of a reviewable and reliable forecast methodology is a continuous process of testing, evaluation, data collection and the revision of the multiple statistical methods, assumptions and adjustments that make up an appropriate demand forecast.

The Council cannot overemphasize the improvements achieved by the Boston Edison Company in its demand forecasting methodology since 1976. The regulatory process was undoubtedly an important influence in these improvements. All parties should recognize this and attempt to make future proceedings less combative.

The record in this case is extensive (see Tr. Vol. I, pp. 2-3, and Tr. Vol. II, p. 2). The parties in this case (EFSC, BECo, and the Attorney General) participated in several technical sessions and prehearing conferences, completed one lengthy round of discovery, and finished a two-day public hearing on June 2, 1981.

This analysis is presented in two sections. First, the Company's First Forecast (1976-1985) and Second Forecast (1981-1990) are compared in terms of growth rates, methodologies and assumptions. Second, nine component parts of the forecast methodology are critiqued: demographics, the price forecast, price elasticities, the residential, commercial and industrial class forecasts, conservation and alternatives, and the peak load forecast.

B. A Comparison of The First and Second Long-Range Forecasts

A comparison of the First (1976) and Second (1981) Forecasts by Boston Edison Company shows a vast improvement in methodology in terms of reasonable statistical methods, documentation, appropriate assumptions, and territory-specific analysis. The more sophisticated and reliable methodology used in the Second Forecast produced much more plausible results in forecasted growth rates in energy and demand. Additionally, the effort expended by the Company in nurturing its in-house expertise has substantially increased the Council's confidence in the Company's ability to plan for the future needs of its ratepayers.[6]

1. First Forecast (1976)

In the original BECo Forecasting methodology, the Company: 1) established past and current trends in electricity sales; 2) projected future trends in sales by applying judgements based on a large number of economic and demographic factors; and 3) modified and attempted to confirm the projections.

In the residential sector, the Company used a simple equation for each of the residential rate codes: it multiplied projected number of customers by billing codes times average annual use per bill to produce projected sales for each code. The methodology did not employ end-use modelling. The Commercial and Industrial models were similar: projected number of customers was multiplied by average use per customer to derive

6 The Council notes that the original 1976 BECo forecast was prepared by a private vendor, Gilbert Management Consultants. Since that forecast was filed with the EFSC, the Company has committed substantial resources for the development of its own in-house forecasting and load research staff that presently includes 11 full-time professional economists, engineers, and analysts. (Ex. BE-4, pp. 1-9).

projected sales.

The assumptions behind the simple trend analysis in these sectors included projections of inflation (5%), GNP growth (5%), and income growth (8-10%); no major acceleration in the cost of basic fuels; continued high interest rates; and other assumptions about the rates of family formation, appliance purchases, appliance efficiencies, conservation, energy prices, income, and load management policies. These assumptions were neither documented nor based on rigorous analysis by the Company's vendor. The result was a forecast which projected annual growth in peak demand at 5.45%; and annual growth in total energy demand at 3.69%.

The Council subjected the approval of the First Forecast to several conditions:

(1) all adjustments to data should be specified and justified;

(2) the Company should use statistical criteria for analyses of trend lines, and justify causal factors;

(3) all judgements should be identified, quantitied and justified.

The First Supplement was combined with the First Forecast and will not be discussed herein.

2. Second Supplement (1978)

The Forecast methodology was relatively more sophisticated. Demographic projections were based on the "cohort-survival" method. A model from Gilbert Associates provided growth projections and trends for household mix. The Company also used U.S. Census data for appliance efficiencies and penetrations. The projections in the residential class were adjusted for price elasticity, assuming a real price increase of 3%

per year. The Company combined an econometric model with trend analysis in the commercial sector. The industrial forecast employed selective trending of past consumption data and some specific information about large customers.

Since 1976, the Company achieved the following: improved quantification of projected demographic changes, and quantification and use of price elasticity effects and macroeconomic conditions. The Council's conditional approval of the Second Supplement sought the following in subsequent filings:

(1) better estimates of new appliance efficiencies;

(2) a review of estimates of annual consumption per appliance;

(3) re-evaluation and restatement of demographic projections, in particular: fertility rates, net migration projections, headship rate projections and customer/household forecasts;

(4) the development of a reviewable price forecast methodology;

(5) more systematic justification for trend line projection of the industrial sector;

(6) analysis of data relating to peak load pricing and load management, and the development of a methodology to reflect their potential impacts; and

(7) more explicit consideration of conservation.

This forecast projected 3.46% annual growth in peak demand and 3.43% in annual growth in energy demand.

3. Third Supplement (1979)

Boston Edison continued to improve its forecast methodology with its filing of the Third Supplement. The Company completed and used a service territory-specific appliance saturation survey, estimated territory-specific short-run price elasticities, and incorporated short and long-term price elasticities in the forecast. BECo also estimated the effects of mandatory time-of-use rates (TOUR), conservation, cogeneration, and alternative energy sources. A territory-specific migration model was developed, and appliance saturations were projected using elements of the New England Power Pool (NEPOOL) regional load forecasting model. Further, the Company estimated industrial consumption by 2-digit Standard Industrial Classification (SIC), and developed a new econometric model for the industrial sector. BECo relied heavily on NEPOOL data and projections in the residential and industrial sectors.

An EFSC Staff Memorandum (dated March 1, 1980) noted concerns with the reasonableness of the NEPOOL model and the applicability of that model to the BECo service territory. The EFSC Staff also offered criticism of the migration model's form and data, the residential model's saturation survey and appliance average use; the commercial model's structure and specification, the consideration of time of use rates and load management, the price elasticity model's structure and specification and, again, conservation assumptions.

This forecast projected annual peak load growth at 2.88% and annual energy demand growth at 2.84%.

No decision was issued regarding this filing. Instead, as discussed in the Background and Procedural History Section, above, this review was "rolled over" to 1980.

4. Fourth Supplement (1980)

After some discovery and several conferences by the parties, review of the Fourth Supplement was suspended, so that review efforts could be focused on the Second Forecast.

5. Second Forecast (1981)

The Second Forecast methodology showed further improvements in documentation and modelling. The major changes from the 1980 filing are:

(1) new migration data;

(2) a re-estimated commercial equation with expanded documentation;

(3) a new industrial forecast methodology based on econometric equations;

(4) additional consideration of add-on heat pumps, alternatives, and new technology.

The results of the improvements in methodology over the five years are striking. The Second Forecast projects annual peak demand growth at 1.71% and annual energy growth at 1.89%. Figures 1 and 2 illustrate the wide margins between the projections in the First Forecast, and energy and demand projections in the Second Forecast. For example, the First Forecast projected summer peak load in 1985 to exceed 3400 MW; the Second Forecast projects just over 2200 MW for the same year (Figure 1). Annual Supplements in the intervening years showed gradual progress toward the more plausible results. The compound annual growth rates for summer peak load and energy in each of the Forecasts and Supplements are shown in Table 1.

While the Council, in the next section, offers criticism of the latest forecast methodology, one fact cannot be overemphasized: Boston Edison has made substantive and significant progress in demand forecasting since 1976. The Council's intent in critiquing any aspect of the methodology is not to discredit the overall forecasting effort, but to help identify and perhaps even quantify the level of uncertainty in the forecast. Such uncertainty is inherently unavoidable. And the

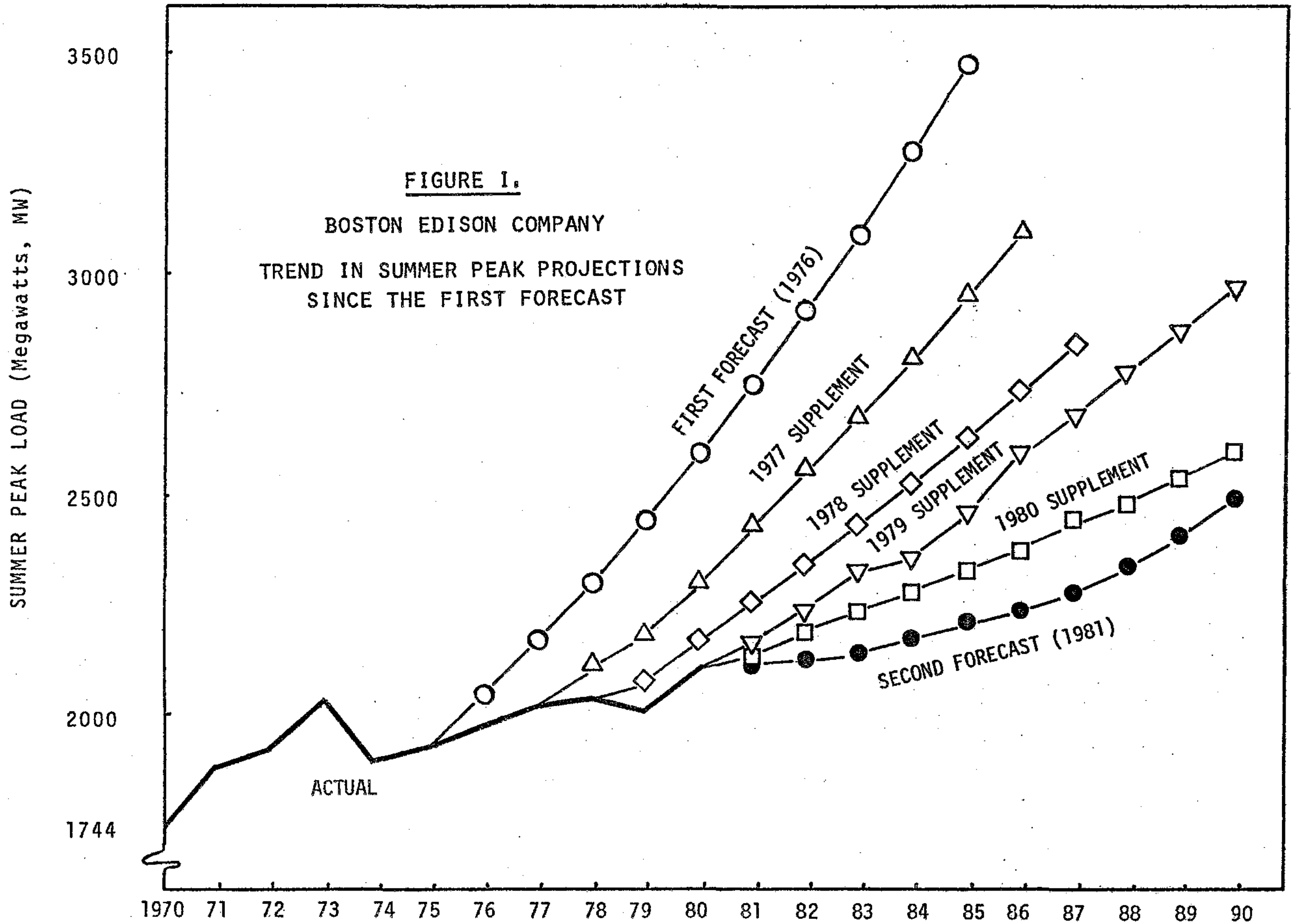


FIGURE I.
BOSTON EDISON COMPANY
TREND IN SUMMER PEAK PROJECTIONS
SINCE THE FIRST FORECAST
SUMMER PEAK LOAD (Megawatts, MW)
3500
3000
2500
2000
1744
1970
71
72
73
74
75
76
77
78
79
80
81
82
83
84
85
86
87
88
89
90
FIRST FORECAST (1976)
1977 SUPPLEMENT
1978 SUPPLEMENT
1979 SUPPLEMENT
1980 SUPPLEMENT
SECOND FORECAST (1981)
ACTUAL

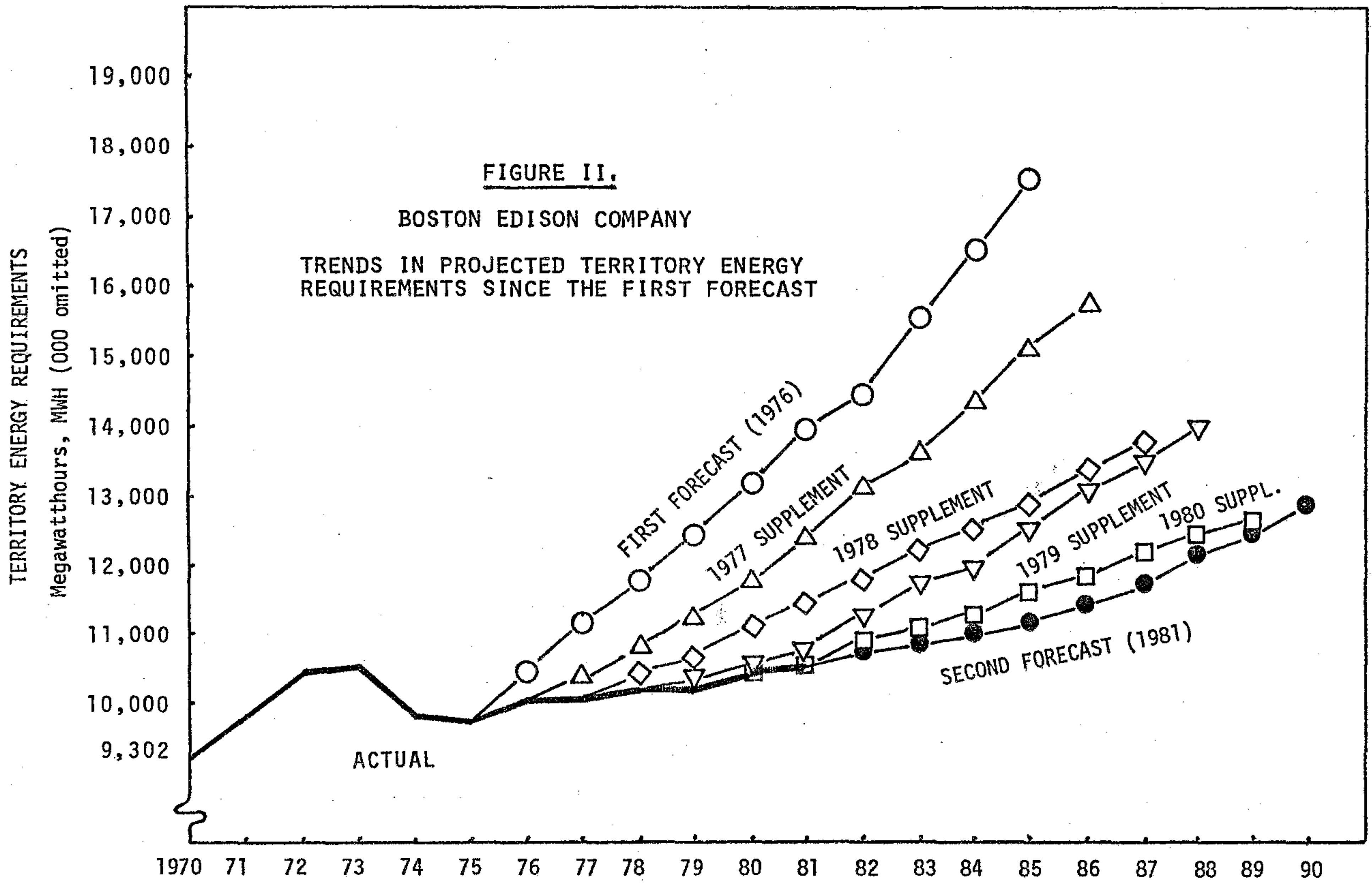


FIGURE II.
BOSTON EDISON COMPANY
TRENDS IN PROJECTED TERRITORY ENERGY REQUIREMENTS SINCE THE FIRST FORECAST
TERRITORY ENERGY REQUIREMENTS
Megawatthours, MWH (000 omitted)
19,000
18,000
17,000
16,000
15,000
14,000
13,000
12,000
11,000
10,000
9,302
FIRST FORECAST (1976)
1977 SUPPLEMENT
1978 SUPPLEMENT
1979 SUPPLEMENT
1980 SUPPL.
SECOND FORECAST (1981)
ACTUAL
1970
71
72
73
74
75
76
77
78
79
80
81
82
83
84
85
86
87
88
89
90

Table 1

Boston Edison Company

Comparison of Ten Year
Compound Annual Growth
Rates from BECo
Forecasts & Supplements

Filing	Growth in demand (Mw) (%)	Growth in energy (Mwh) (%)
1st Forecast (1976)	5.45	3.69
1st Supplement (1977)	4.44	3.41
2nd Supplement (1978)	3.46	3.43
3rd Supplement (1979)	2.88	2.84
4th Supplement (1980)	1.94	1.95
2nd Forecast (1981)	1.71	1.89

Source: EFSC Tables E-8 and E-11;
EFSC Staff Calculations

underlying causal factors are forever changing.

C. The Methodology for Demographics

The Company used the NEPOOL model's cohort-survival methodology and software to forecast population and households in the service territory. Because the NEPOOL model's migration submodel does not perform well for the BECo service territory, the Company used the NEPOOL model to calculate population based on birth and death rates only. The Company then calculated net migration with its own migration model.

BECo should be commended for taking the pains to develop a well-documented territory-specific model for migration -- a key demographic parameter in the BECo service territory. A reliable net migration model would have to account for territory-specific behavior. The Company's attempt is admirable given the difficulty of the forecasting problem.

The Company calculated historical migration from 1970 to 1977 by subtracting the actual 1977 U.S. Census estimate of population from the NEPOOL-generated (without migration) estimate for the same year. The Company assumed that the difference was actual net migration. However, the difference is comprised of net migration plus some measure of error in the NEPOOL-generated estimates and the Census estimates. It is assumed that this difference will be constant over the forecast period (Ex. BE-10, Question 2). There is no way of measuring the degree of error present in either the NEPOOL or Census estimates. It could well be that any variances are similar, i.e., they either overestimate or underestimate the true population. Therefore, the methodology of comparing the two estimates is a reasonable means of assessing net migration in a given year. This method of calculating net migration has been shown to be accurate by comparing model generated migration with vital statistics migration (Ex. BE-3, p. 9). In no year did the model's estimate of migration deviate from vital statistics migration by more than 0.25% of the service territory's population.

The Company used the following equation for predicting migration:

$$M = a + b_0x_0 + b_1x_1$$

where

M = predicted level of migration

a = constant

b_0 = employment coefficient of U.S. employment growth

x_0 = U.S. employment growth

b_1 = employment coefficient of BECo employment growth

x_1 = BECo employment growth

The model is potentially problematic for two reasons. First, the boundaries of the BECo territory do not coincide with the boundaries of areas for which data and analyses are available. For example, the BECo service territory accounted for only 58% of the tri-county[7] area population in 1979. The reasonableness of assuring that tri-county migration trends are applicable has not been demonstrated (Ex. BE-11, Question D-11).

---

7 The "tri-county area" includes Suffolk, Middlesex, and Norfolk counties.

The Company could perhaps remedy this problem by examining available data for the service territory, the tri-county area, and the SMSA for a number of parameters (e.g., age, characteristics, employment) that are theoretically important in migration behavior. The results of such an analysis could be used to either support the Company's current model or to provide a basis for adjustments of the results of a migration model.

Second, the model provides only a rough proxy for variables that explain the behavior that results in net migration. The "employment growth" variables represent economic opportunities, but many other variables, especially distance between opportunities and potential migrants (Ex. BE-10, Question 3), age characteristics that relate to migration, and historical migration patterns, may not be adequately accounted for by the proxy -- "employment growth" (Ex. AG-1, pp. 10-11). The Company recognized this problem (See Ex. EFSC-5, Appendix pp. 43-45), but tried to develop a model that would perform well (statistically) within the given data constraints. As the Attorney General demonstrated, BECo's migration model may not produce a plausible forecast if the values of the independent variables are outside a narrow range of values (Ex. AG-1, pp. 16-19). The Council recognizes that migration is a complex, if not impossible, phenomenon to precisely model. Although the regression estimates are statistically significant, the Company does believe that the equation could be improved upon by testing variables that measure the "residential satisfaction" associated with an area. (Ex. BE-18, p. 5). The Council encourages such research if meaningful and appropriate data can be obtained.

The second issue in the demographics section is the Company's forecast for the number of households in its service territory. Household size formation, relative to general population trends, is a critically important determinant of energy demand by residential ratepayers since the energy used for dwelling space heating and air conditioning is largely independent of the number of people in the household. Hence, as an illustration, if aggregate population is stable or slightly declining, but the average household size is getting smaller, energy demand per capita may significantly increase in spite of major conservation efforts. The Company's current model relies on national household formation trends in generating estimates of people per household and the number of households. However, the BECo service territory has characteristics that appear to be quite distinct from national averages. For example, the relatively large student and young professional population in the BECo territory are likely to affect household formation trends. The Company has indicated that it does not have any particular knowledge in that regard (Ex. BE-10, Question 1). Again, the Council would be more confident that the demographics models (and the related residential class forecast) were reliable if the Company would expand its knowledge of territory-specific demographic trends. The Company has committed itself to this effort. (Ex. BE-18, p. 5).

The Attorney General had a number of criticisms of the demographic submodel. (Ex. AG-1, pp. 7-23) First, the Company should note the suggestions for documentation (Ex. AG-1, pp. 7-8, 12-13); the forecasters have done the work and could present it more clearly in the next filing.

Second, the A.G.'s point about the need to justify use of NEPOOL derived data (AG-1, pp. 13-15) is valid. Although the A.G. did not make any practical suggestions for adjusting the NEPOOL-derived data (Tr. Vol. I, pp. 111-112), the Company should look closely at the differences between NEPOOL and Vital Statistics data with the purpose of making the data reflect the characteristics of the BECo territory as closely as is practical. Given that the computed discrepancies between the two estimates are slight, as discussed above, the Council does not anticipate that such effort would materially change the forecasts. However, the Company has indicated that it will attempt to derive more appropriate parameters affecting migration which are territory specific. (Ex. BE-18, p. 6).

The A.G.'s criticism of BECo's use of the Boston Consumer Price Index variable (Ex. AG-1, p. 11) and of the changes in income distribution (Tr. Vol. 1, 116) are here recognized. However, the A.G. did not adequately substantiate its criticisms concerning the historical ratio of BECo territory to tri-county population (Ex. AG-1, p. 21 and Table 3, Tr. Vol. I, 113-114) and the declining trend in family size (Ex. AG-1, pp. 22-23; Tr. Vol. I, p. 114-116). With respect to the use of price indices, the Company believes, and the Council concurs, that the relative cost of living in the BECo service territory is an important determinant of migration. The Company has indicated its willingness to include both the Boston and U.S. Consumer price indices in the forecast equation in its attempt to capture the effect of this factor. (Ex. BE-18, p. 7).

D. The Methodology for the Price Forecast and Price Elasticity

The most progressive part of Boston Edison's demand forecast is the territory-specific electricity price forecast. Price is a key variable in the residential, commercial, and industrial submodels, either directly or as a component of price elasticity adjustment. The Council realizes the difficulty and uncertainty inherent in price forecasting, and recognizes and commends the Company's progress.

1. Description of the Price Model

The Company projected real (uninflated) electricity prices by estimating annual average prices based on projections of base revenue requirements and fuel costs. For base revenue requirements, the Company made several simplifying assumptions: constant rate schedules, constant load shapes, constant real tax rates, constant relative shares of base revenues among residential, commercial, and industrial sectors, and no conversions of generating plants from oil to coal. Two of the primary factors in the base revenue forecasts are operation and maintenance costs and the scheduling of new generating units. The Company assumes that in real terms, the base price decreases slightly over the forecast period (1981-1990) (See Ex. BE-11, Question p. 14).

The fuel costs forecast is based on the projections of oil prices by A.D. Little (February, 1980)(Ex. BE-11, p. 1) and the scheduling of generating units. The simplifying assumptions are constant average heat rates and no "coal conversions" of existing oil-fired units. The Company assumed, again in real terms, that its annual average fuel cost would decrease over the forecast period, reflecting the lower costs of nuclear fuel for the then-proposed Pilgrim 2 plant.

The role of price in the BECo demand forecast is an important one.

First, price (lagged one year) is an independent variable in the submodel used to forecast sales in the commercial class. Second, electricity price affects the values of a key variable -- megawatts per employee -- in the industrial submodel (Tr. p. 89). Third, price is the primary variable in the estimations of price elasticities used to adjust the projections in both the residential and commercial submodels.

The record (Ex. BE-1, p. 102; Ex. BE-10, question 34) demonstrates that the commercial model is somewhat sensitive to various price assumptions. In addition, the adjustments for elasticity are significant in the residential and commercial sectors (Ex. BE-1, pp. 62, 97).

2. Critique and Suggestions for Improvements

The price model has some shortcomings which cause the Council to question the potential reliability of the price forecast methodology. The Council is not confident that the methodology predicts what is most likely to occur. The Council suggests five improvements that might strengthen the methodology and facilitate the Council's review.

First, the Company should expand the documentation of the price forecast methodology. Current documentation is inadequate to the task of explaining a fairly complex and interesting methodology, describing the process of development and specification of the model, and presenting the model's data base. The documentation in the 1979 forecast (Ex. EFSC-4) needs to be updated and expanded to incorporate the items and explanations which were requested in 1981 discovery proceedings. These include explicit treatment of the costs and projected in-service dates of all anticipated changes in the Company's supply plan that post-date the cancellation of Pilgrim II. Due to the importance of the price forecast, the EFSC Staff will continue to seek thorough and complete documentation in future reviews.

The second improvement might be to keep the fuel cost forecast up to date to take into account such polical and regulatory events as the decontrol of oil and gas prices. Currently, the Company assumes no effect from such decontrol (Ex. BE-10, Question 8(b)). The Council is not looking for fuel price readings from the proverbial crystal ball. Rather, the Company should follow through on its stated intention to monitor events in oil producing countries, compare past price trends, and gain insight into how the political process affects prices (Tr. Vol. II). Sensitivity analysis on the fuel price variables might better identify the risks of uncertain events which impact those prices.

The Company's use of the A.D. Little fuel price forecast is valid, but such a forecast needs to be updated often. By using the February 1980 fuel price forecast, Boston Edison underestimated the 1981 fuel price of oil by about 4 dollars per barrel as of March 1981 (Ex. BE-10, question 8(a)). The effect of such an underestimation, $62 million in 1981, is illustrated in Table 2. This example is not intended to criticize the forecasters, the Company prepared the 1981 forecast before the large increase in oil prices that occurred during the winter 1980-81. Rather, the underestimation illustrates the importance of updating the ADL numbers and monitoring oil markets and political developments.

Table 2

Boston Edison Company

Effect of Underestimating Fuel Price

Unit	1981 Projected MWH	BBL/MWH	BBL
Mystic 4, 5, 6	1,892,000	1.85	3,500,200
Mystic 7	3,171,000	1.59	5,041,890
New Boston	4,191,000	1.59	6,663,690
L Street	46,000	1.37	63,020
Wyman 4	80,500	1.56	125,580
Total BBL			15,394,380
Fuel Cost at $33/bbl			$508,000,000
Fuel cost at $37/bbl			$570,000,000
Difference			$ 62,000,000

Source: Exhibits BE-10, question 8 and BE-11, Question p. 3(a).

A third improvement in the price forecast methodology relates to a few simplifying assumptions. A complex forecasting problem such as projecting electricity price requires some assumptions to make the problem manageable. However, the Council would have more confidence in the price model if the Company did not assume that the relative shares of base revenue among customer classes would be constant over the forecast period (Tr. Vol. II, p. 34). The Company should attempt to differentiate among customer classes in terms of share of revenue because actual rates vary by class and because growth rates in energy requirements are forecasted to differ by class.[8] Although the magnitude of the effect of not differentiating among customer classes is not quantified in the record, the importance of the price forecast justifies analysis of the problem by the Company.

The Company has indicated that while it agrees that the price model could be "richer" if the relative shares of the base revenue among customer classes were allowed to vary over the forecasting period, the Company is not in a position to postulate what the relative rates will be. The final decision on rates is within the purview of the Massachusetts Department of Public Utilities. Therefore, hypothesizing a change in the relative shares of base revenue among customer classes would be inappropriate. (Ex. BE-18, p. 17). The Council does not expect the Company to second guess the short-term policies of the MDPU, but the Department has promulgated regulations for rate restructuring

8 Compound annual growth rates (1981-1990) in energy requirements by class are:

residential with electric heat	3.7
residential without electric heat	0.7
commercial	1.7
industrial	2.2

(Ex. BE-1, p. 147)

based on peak load pricing, i.e., marginal cost pricing.[9] Given the long-term focus of the Council's statutory review, it would not be presumptuous for the Company to employ assumptions in their long-term planning in which the intent of DPU 18810 is effectively realized. The Council also suggests that the public may be better informed if both sets of assumptions were employed and the results compared.

Additionally, the Company's method of calculating base revenue requirements tends to smooth likely year-to-year fluctuations in real price. Given that short-run elasticities are sensitive to annual changes in price, the smoothing of fluctuations could be lending a downward bias to price elasticity estimates.

Fourth, the uncertainty in forecasting electricity price needs to be addressed explicitly. The only sensitivity analysis in the record illustrated the effect of different energy growth assumptions on nominal price levels (Ex. BE-11, question p. 10, p. 11). No alternative growth scenarios were available for projections of fuel oil price (Ex. BE-10, question 8(b)). Sensitivity analysis would be especially useful to test the various effects related to forecasted fuel price levels: costs, in-service dates, and scheduling of new or converted generating units, and assumptions about conservation, load management, and renewable energy sources. The Company has indicated on the record a willingness to attempt such sensitivity tests in future filings. (Ex. BE-18, p. 10).

---

9 D.P.U. 18810, December 29, 1977.

Fifth, the Company real price forecast appeared to be especially sensitive to assumptions about the cost and in service date of Pilgrim 2 and the scheduling of other units (Ex. BE-11, Question P-12). For example, between 1986 and 1988, the first two years during which Pilgrim 2 was assumed to be operating, the forecast suggests the fuel charge will drop from $.0453 to $.0305 (33%), the base charge will increase from $.0255 to $.0333 (31%), and the total charge will decrease from $.0708 to $.0638 (10%). (Ex. BE-11, Q. P-12). While Pilgrim 2 did not account for all of the change, the Company expected a decline in price in 1987 due to Pilgrim 2 coming on line (BE-11, Question P-12). The uncertainty about the now cancelled Pilgrim 2 expressed by the Company (Ex. BE-11, Question P-4; Tr. Vol. II, p. 38) highlights the need for sensitivity analysis and the presentation of various alternative scenarios. While the forecasters cannot eliminate uncertainty, they are able to directly address the uncertainty and analyze the likely effect of probable and extreme events and changes in factors that influence electricity price.

3. Price Elasticity

Boston Edison estimated the price elasticity of demand using regression equations (residential and commercial classes) and a review of the literature (industrial class). The residential elasticity equation included an attempt to model the declining block structure of electricity rates.

The Company uses its price elasticity estimates to adjust projected energy requirements in the residential (short-run elasticity) and commercial and industrial (short and long-run elasticities) customer classes. For example, in 1990 short and long-run elasticity effects are expected to reduce the projected commercial sector requirements by 402 GWH or 7% of the model's unadjusted level.

The Company's efforts to account for the price elasticity of demand are quite commendable. In light of the importance of price elasticity to the demand forecast, the Council takes issue with the Company on a few aspects of its estimates and subsequent adjustments.

First, the documentation of the price elasticity estimates would be more suitable for review if an updated version of Appendix H in the 1979 Supplement (Ex. EFSC-4) were in the current appendix and if a sample of the short run elasticity equations were presented in tables with definitions of the variables and symbols. The Company has agreed to do this. (Ex. BE-18, p. 10).

A second problem is that the Company's price elasticity methodology employs a rather narrow interpretation of long-run effects. In spite of testimony to the contrary (Tr. Vol. II, p. 105), the Company methodology restricts the long-run effects of price elasticities to appliance efficiency improvements (Ex. BE-1, Appendix p. 44). The Council agrees with the Attorney General's assertion that long-run price effects should not be equated with appliance efficiency improvements (Ex. AG-1, pp. 4-5), and notes that the Company has failed to address the four impacts listed in the AG's testimony, which could substantively change the residential forecast.[10]

---

10 The four long run impacts of price mentioned by the Attorney General are (quoted from Ex. AG-1, p. 4-5):
1. the impact on the number of appliances bought;
2. the impact on the size of the appliances purchased;
3. the impact on insulation of homes and of water heaters;
4. the impact of price on appliance efficiency levels after 1985, or more generally, the possibility that appliance efficiency improvements will, in the forecast period, exceed the federal targets (BECo has projected that the targets will be met, but not exceeded).

Third, the Attorney General criticized the Company's method of accounting for the 1974 price increases in its elasticity estimates (Ex. AG-1, p. 6). The Council agrees that the Company's special treatment of the 1974 price increase is not entirely justified for estimates of long-run price elasticity. While special consideration of unusual changes is valid and useful, the Company's rationale in Exhibit BE-1 (p. 85) and BE-11 (Question E-2) is not convincing. This issue takes on greater importance given the large electricity price increases in 1979 and 1980 which the forecasters will have to interpret in future forecasts (Tr. Vol. II, pp. 112-113). The Company could experiment with dummy variables or with lagged structures for long-run behavioral responses to price, being careful to differentiate long-run from short-run responses.

Finally, the Council does not agree with the Attorney General's assertion that BECo's price elasticity calculation for the residential sector is "unacceptable" (AG-1, p. 4). The results on Table 11 (BE-1, p. 67) indicate only that projected real price changes are associated with short-run elasticity effects in the same direction (positive or negative).

The price elasticity modelling effort has evolved to a point where the Company believes that the price elasticity estimates may not become much more accurate (Tr. Vol. II, p. 107). However, the Company intends to gather more information on cross price elasticities (Ex. BE-10, question 11; Tr. Vol. II, p. 108). The Council suggests that BECo also explore price elasticity by industry in the commercial and industrial sectors. A data series, apparently unavailable now, would allow the Company to analyze classes more explicitly.

E. The Methodology for the Residential Sub-Model

The residential class sub-model is the most complex forecast methodology in the Boston Edison Forecast. In the methodology, the forecasters used estimates of households from the demographic model, appliance saturations from a 1978 BECo survey, and a saturation trend developed from the NEPOOL model to calculate appliances on-line in each year of the forecast period. The Company then calculated an average electricity use per appliance based on 1972 data (Edison Electric Institute) and appliance efficiency guidelines (Department of Energy). These estimates were then adjusted for short-run elasticity, inter-appliance substitution, alternative energy, conservation, and new technology. The resulting forecast of residential energy consumption showed a 1.1% compound annual growth rate for 1979-1990.

Perhaps because so many issues are inherent in the residential customer class, the Attorney General gave this sub-model more attention and criticism than other parts of the forecast (Ex. AG-1, pp. 23-43). The Council finds that the Attorney General's criticisms, although not all well-substantiated, (Tr. Vol. I, 107-115), appear to be, in part, valid and support the overall theme of the A.G.'s testimony: that the errors, inconsistencies and shortcomings of BECo's methodology potentially undermine the reliability of the forecast (AG-1, p. 3; Tr. Vol. I, 47-48). The record in this case includes much discussion of issues in the residential sub-model that need not be repeated at length herein.

The Council believes it would be most useful to the Company to focus this analysis on what the Council perceives to be the more important issues in the residential methodology. The Attorney General did not have an opinion on which parts of the residential methodology contributed the most uncertainty to the forecast (Tr. Vol. I, p. 125). This is unfortunate, because specific criticisms would be much more useful to the Council. Therefore, the Council would like to see the Company concentrate on improving the residential methodology in some specific areas.

A major issue in the residential demand forecast is the lack of territory-specific data used in key parts of the methodology. Appliance saturation trends and major appliance average use estimates, which are critical determinants of the final residential forecast, were solely based on state or national level estimates. Specifically, BECo's use of state and national data, without adequate evidence that it is representative of the BECo service territory, creates questions about whether the forecast procedures are reliable or appropriate. The Council notes that other electric utilites with comparable (or less) resources are aggressively developing territory specific data bases. The Company has indicated that "subject to resource limitations" it "will attempt to cultivate territory specific data." (Ex. BE-18, p. 14).

The NEPOOL model's income-saturation trends used by BECo must be considered for their applicability to the BECo territory. The Company has not presented any empirical or intuitive evidence that the NEPOOL data or model assumptions apply to their service territory (See Ex. BE-10, questions 17 and 26; Ex. BE-11, question S-15). Further, by relying on the NEPOOL model for saturation trends, BECo has excluded the possibility of explaining trends as they occur in their own territory. The record does not show that income is the best explanatory variable, nor that either BECo or NEPOOL have considered alternative specifications (Ex. BE-10, question 24). The Company argued that there was "excellent agreement" between its own 1978 saturations and the NEPOOL forecast (Ex. BE-10, question 26). However, a cross-sectional comparison (i.e., at a single point in time) does not provide adequate evidence that a particular trend is representative of another trend. Therefore, the Council has little basis upon which to judge the NEPOOL income-saturation trend as adequately representative of the BECo trend.

Further, the reasonableness of the NEPOOL saturation equations must also be questioned. The single and multi-family income and appliance data base used by NEPOOL to develop the equations appears to have been condensed to thirteen observations for each variable (Ex. BE-21). Those observations represent average income levels; such an aggregation loses the potential richness of the data base by eliminating all individual variation. Thus, the reliability of the predictors is reduced.

The second major issue of the residential forecast is the use of Edison Electric Institute estimates for appliance average use, and the basis for efficiency changes over time. The Company has neglected to derive its own estimates of average use from rate or survey data. Again, important characteristics, specific to the BECo territory, have not been considered in the estimation of appliance average use. In particular, electric water heater average energy usage is apparently sensitive to family size and dwelling type (single family or apartment), yet BECo has failed to recognize this in its forecast (Ex. AG-1, p.

37). The estimate of electric space heating usage is quite important as a major consuming end-use and yet the Company has not developed its own estimates of consumption, or even considered the wide number of variables known to affect it (Ex. BE-10, question 30).

F. The Methodology for the Commercial Sub-Model

The Commercial forecast methodology employs a single-equation econometric model (Ex. BE-1, p. 72). The model is based on the assumption that electric energy demand in the commercial sector is primarily dependent on the level of macroeconomic activity. The variables selected to explain demand in the equation are the average real price of electricity, the number of households in the service territory, and sales in the sector lagged one year ("L SALE"). The forecast from the equation was adjusted for effects of conservation, Harvard's cogeneration plant (MATEP), and short and long-run price elasticity. The projected compound growth rate for 1979-1990 was 2.0% (Ex. BE-1, p. 2).

The Commercial Forecast is the best documented sub-model in the 1981 filing. The model selection process is well-explained and well-organized. If more regression results were added to the appendix, this submodel would meet a degree of reviewability that the Company could strive to achieve in other sub-models. However, the Commercial sub-model has certain methodological weaknesses. Because 43% of BECo's current demand, and 47% of projected growth in kwh sales over the forecast period are in the commercial sector (calculated from Ex. BE-1, Forecast Vol. I, Table E-8), improvement in the commercial sub-model is essential to overall improvement in the BECo forecast.

The major issues in the Commercial Forecast are selection of the final specifications and the limitations of the model. First, the selection of the final specification seems to reflect over-reliance on statistical tests (Ex. AG-1, pp. 43-45). A priori considerations should also be an important factor in the selection of the final specification. In the commercial sector methodology, the Company did not sufficiently state the reasons and criteria for rejecting theoretically valid equations.

The second, and most important, issue is the inherent limitations of the final model for projecting long-range power requirements in BECo's commercial class. These limitations are related to the specification of the model variables, uncertainty in the model, and the level of detail in the data used in the modelling effort.

The final model, as specified on page 77 of Volume I of the Forecast, is more appropriate and reliable for a short-range forecast than for long-range projections. The "L SALE" variable measures a certain amount of inertia in the system. Over a two or three year period, the "L SALE" variable is theoretically sound, would likely strengthen the statistical results of the model, and would probably not be affected by sources of uncertainty. However, this "autoregressive" feature of the model may lose reliability if the forecast period is extended beyond a few years. The customer behavior that underlies electricity consumption in the commercial class is not likely to be static over the entire ten-year forecast period. The structure of the commerical sector could change over that time span, as it has over most of the post-war era. For example, public services may be reduced, eliminated or provided by private businesses; retail establishments may increase automation significantly, many public school buildings may be closed or used more or less intensively, and commercial class customers may also alter their hours of operation.

The other inherent limitation in the final commercial class model is the level of detail in the data base. Although many variables were included in the data base, the data are not sufficiently detailed. That is, the Company attempts to explain power sales to the commercial sector by aggregating a wide variety of end uses rather than choosing models that explain the behavior that underlies power consumption in those aggregated end uses. Office buildings are lumped together with hospitals, restaurants, and supermarkets, in spite of quite different end uses and patterns of consumption. The BECo forecasters could significantly improve the commercial forecast with a better data base.

The development of any forecasting methodology should begin with information about the structure, variable interrelationships, and the dynamics of the system being modeled. Without such information, identifying and applying relevant theories and appropriate methods would be difficult, at best. A single-equation estimate of the commercial sector may fit the aggregate data quite well, but the important consideration is how well that equation models electric power use in the commercial class in the future. To achieve this end, the Company has renewed its promise to develop a commercial sector database, disaggregated by two-digit SIC codes. The Company submitted a copy of a questionnaire sent to a sample of commercial customers in its service territory (Ex. BE-13). The questions are thorough, and if the responses are adequate, the resulting database should foster substantive improvements in the commercial model. Furthermore, the data could be very useful for load management and supply planning in general.[11] The Council anxiously awaits the results of this effort.

G. The Methodology for the Industrial Sub-Model

The Company used an "eclectic" approach to model electric sales to the industrial sector (Ex. BE-1, p. 104). Based on the assumption that electric sales in this class are positively related to the level of macroeconomic activity in both the Boston area and the nation, BECo used econometric models to derive employment forecasts for individual SIC industry groups. The independent variables were, alternately, state employment and GNP. Next, an intensity of electricity usage (mwh per employee) forecast was derived using the NEPOOL model's state intensity growth rates and the actual electricity intensiveness observed in the BECo territory in 1978. The variables used to calculate electricity intensiveness included price, price elasticity, and price elasticity aging factors. The product of the employment projection and the electricity intensiveness projections was electricity demand. Total industrial demand equalled the sum of the results in the twenty SIC industry groups. Finally, the forecast was adjusted for conservation, new technologies, and time of use rates. The resulting compound annual growth rate in the industrial class (1979-1990) was 1.6%.

The Council recognizes the difficulty of forecasting sales to the industrial sector in the BECo territory and notes that the Company has made progress toward a well-documented, reliable forecast.

---

11 See Condition 2 of the Forecast Decision, infra.

The Company presents a theoretical basis for the industrial class forecast methodology (Ex. BE-1, p. 104), but does not sufficiently support the theory with knowledge of the industrial class and its energy use determinants. The "basic assumption" that electric sales to the industrial sector "are positively related to the level of economic activity of both the Boston area and the nation" (p. 104) is clear and reasonable. The problem is that the Company's scarcity of specific information on industrial activities and energy usage limits the forecasters to using single-equation estimates based on such broad measures of economic activity as Gross National Product and employment by 2-digit Standard Industrial Classification (SIC) industrial groups.

Additionally, certain adjustments to the industrial forecast (Ex. BE-1, p. 112) tend to weaken the methodology. The Attorney General (Ex. AG-1, p. 46) argues convincingly that the smoothing adjustment is not valid. Indeed, the "trough" for four of the industries is in 1989. Growth rates could be barely positive until sometime closer to 1995. The smoothing adjustment, in this case, would slightly over-estimate growth 1981-1990. Furthermore, the "levelizing" technique is based on the assumption that the sources of the differece between the BECo historical sales in 1979 and the model's value for 1979 will remain constant throughout the forecast period. The record shows no evidence to support such an assumption. The adjustment for 1980 sales at the aggregate level is even less convincing.

Moreover, some of the regression results for the selected equations are extremely weak. For example, the equation for SIC 35 would be statistically insignificant at a 95% confidence level, and the equation's uncorrected R^2 (.19) is low. Likewise, SIC's 23, 25, 26, 28, and 34 have weak results by the R^2 criterion. If the equations do not fit the actual data well, the chance of forecast data producing accurate projections is small unless supported by complementary end-use analysis.

Although statistically fitting historical data with regression equations is a reasonable method, the EFSC wants to emphasize the importance of theory or a priori considerations. Theoretical assumptions may override statistical criteria, especially if major structural changes in the economy or within specific variables (such as oil prices) are taking place. For the BECo industrial forecast, in particular, projections may go outside the bounds of historical data. Models based on theoretical assumptions about how particular industries will fare in the service territory in relationship to variables such as military expenditures and energy prices would make the Council more confident in the industrial forecast than equations with better statistical results, but weaker theoretical bases. The Company needs to strengthen the theoretical (i.e., intuitive) basis for its industrial model. If the available data in the service territory is insufficient or if a sample of firms in a particular SIC group is too small, the Company would be justified in using data on areas outside the territory. While the most reliable model might ultimately be based on territory-specific data, the Council is not averse to "second best" approaches in the short-term if they are based on sound theory and good documentation.

The energy intensiveness assumptions (Ex. BE-1, p. 111) raise questions about the applicability of the NEPOOL Model's Massachusetts energy intensiveness growth rates to the BECo territory, and about the reasonableness of the NEPOOL Model's energy intensiveness forecast. The importance of the forecast of energy intensiveness (electricity use per employee) is illustrated by Table 3, which shows forecasted annual growth rates for employees, mwh/employee, and sales.

For each of the industries, the growth rate for mwh/employee carries proportionately more weight in terms of growth in sales than the growth rate in employees. If the energy intensiveness forecast were not accurate, the effect on the growth rate in sales would be significant.

The Company stated that "no evidence exists that indicates the growth of intensity of electric energy use will vary significantly from that of the state" (Ex. BE-1, p. 111). However, the record shows no evidence of the applicability of the state projections to the BECo territory. The Company has the burden of showing that its assumptions are appropriate.

The reasonableness of the NEPOOL model's energy and employment forecasts has not been demonstrated by either BECo or NEPOOL. The sample used by NEPOOL to compile data for industries is too small and too aggregated to be applied with confidence to the BECo territory (Ex. EFSC-3). Further, both NEPOOL (Ex. EFSC-2, II-1) and BECo (Tr. Vol. II, 90) cite a book by Clopper Alman, Jr. et al[12] which purportedly explains the theoretical structure of a model of growth rates for productivity per employee. The Council would argue that whatever the merits of that model, one qualification in particular[13] raises doubts about strict

12 Clopper Almon, Jr., Margaret B. Buckler, Lawrence M. Horwitz, Thomas D. Reinbold, 1981: Interindustry Forecasts of the American Economy (Lexington, Mass. E.C. Heath and Co., 1974).

13 ibid, p. 180. Referring to labor productivity growth rates the authors state that "these productivities are labor productivities only in the crudest sense. They completely ignore capital's contribution. Moreover, they do not measure the present level of even that crude labor productivity, but only its rate of change".

applicability of its theoretical structure to the BECo service territory. Either the Company or NEPOOL needs to make a more convincing case for the reliability of the energy intensiveness variable.

BECo has made encouraging progress and has included the best available data in the industrial forecast. For example, BECo-specific employment data by 2-digit SIC, BECo price and price elasticity forecasts, and industry-specific knowledge (p. 110) were used prominently in the model. The Company needs more specific information on the service territory to improve the statistical analysis and to support judgements about certain industries. But, judgement alone is not convincing; the Company should include more detailed information on large customers and industries at the 3- and 4-digit SIC levels. On the other hand, all industries need not be fully disaggregated if there is no substantive gain to the overall forecast.

Table 3

Boston Edison Company

Forecasted Growth Rates for Major Industries: 1981-90

SIC		% of 1979 Industrial Sales	Forecasted Annual Growth Rates Employees(a)	mwh/emp(b)	Sales(c)
36	Electric Machinery	24	+3.5	+0.6	+5.1
38	Instruments and Related	17	+1.6	+0.9	+2.9
20	Food and Kindred	13	-2.7	-0.9	-3.6
35	Machinery, except Electrical	11	+0.3	-0.3	-0.2
26	Pulp and Paper Products	7	-0.1	+0.5	+0.3

Sources: (a) BECo 1981 Forecast, Table 4

(b) BECo 1981 Forecast, Table 7

(c) BECo 1981 Forecast, Table 10

H. The Treatment of Conservation

Boston Edison's treatment of conservation in the forecast methodology is adequate, but generally weak compared to other determinants of electricity demand. In the residential sub-model, the Company accounted for conservation by assuming certain appliance efficiency improvements, by estimating short-run price elasticity effects, by calculating the impact of federal and state conservation programs (mandated as of 1980), and by calculating the effects of renewable sources of energy that would reduce demand for electricity from BECo. In the commercial model, BECo estimated short-run and long-run price elasticity impacts and calculated likely effects of mandated conservation (held constant 1982-1990) and time of use rates. Impacts on demand attributable to new technologies were assumed to be absorbed by price elasticity effects.

A sector by sector approach to forecasting conservation is reasonable, but the Company's present methods tend to underestimate conservation in the service territory. First, the end-use residential model is well-suited for calculation of the effect of appliance efficiency improvements. However, conservation also includes behavior in the use of appliances, choice in size of appliances, and capital improvements to home (e.g. insulation of buildings and hot water tanks) (Tr. Vol. II, 104-105). BECo has not accounted for these factors, nor has it made a convincing case that it has accounted for conservation in the commercial and industrial sectors. While mandated coservation is important to consider, and price elasticity effects would account for much of the likely conservation, the Company has overlooked potential conservation related to changes in technology and production processes.

Further, the analysis of renewable energy sources is inadequate to the task: the estimations were poorly documented, and discrepancies in calculations were found (Ex. AG-1, 41-43).Conservation, load management, and alternative energy sources will be discussed further in the analysis of BECo's Supply Plan.

The Company's evaluation of the impact of time-of-use rates (Ex. BE-1, p. 133) is based on reasoning that addresses only the short-term.

In sum, the Council finds a need to improve the various methods of estimating conservation. The Company needs to submit more evidence and better document its reasoned judgments before the Council can be confident that conservation has been adequately assessed and estimated. To the Company's credit, BECo has indicated in the record its plans for a major survey of industrial and commercial customers for the purpose of assessing conservation trends. (Ex. BE-18, p. 24). The Council is pleased with this commitment and encourages BECo to make this data collection process an on-going, comprehensive effort.

I. <u>The Peak Load Forecast</u>

The Company projected the system's annual peak load by estimating coincident peak demands for each customer class, and dividing those values by the annual energy required by the respective classes to yield peak factors by class, i.e.:

$$\text{Peak Factor} = \frac{\text{Class Peak Coincident with System Peak}}{\text{Annual Class Energy}}$$

BECo's projected annual peak load is the sum of the products of annual energy (forecast) and peak factors by class. The peak factors were held constant over the forecast period.

The Company's peak load estimates by class are based on BECo load research data and data borrowed from the electric utility industry. The latter will be used less as the Company compiles more territory-specific load research data (Ex. BE-10, questions 55, 56). The Company's research efforts enhance the methodology and increase the Council's confidence in the reliability of the forecast.

The weakness of the peak load forecast methodology is the assumption that peak factors will be constant over the forecast period. Although the Company argues that the assumption is reasonable (Ex. BE-10, question 55), actual peak factors have varied by as much as 27.6% (see Table 4), since 1975.

It is not clear whether the values of peak factors assumed by BECo follow some discernable trend, vary around some mean, or follow no predictable pattern. The significant differences in peak factors over a few years indicate a need for the Company to examine its load research data, identify determinants of change in peak factors and identify actual trends, or likely means, in the values of peak factors. Although the overall approach to peak load forecasting is quite reasonable, the assumption of constant peak factors potentially lessens the reliability of the long-range load forecast. The problem may also be a simple matter of documentation.

The Council also notes that the Company is monitoring the effects of quartz heaters on the winter load shapes (Ex. BE-10, question 58). Although the ultimate effects could be minor, this subject offers an example of the Company's efforts to monitor current developments in the service territory. Similar efforts may be directed profitably at other

Table 4

Boston Edison Company

Comparison of the Percentage Difference Between Actual Peak Factors in Various Years Since 1975.

Customer Class	Years	% Difference Summer	% Difference Winter
Residential	1975/1978	-27.6	17.6
Commercial	1976/1978	16.2	-9.7
Industrial	1977/1978	15.9	1.9
Lighting	1977/1979	--	-19.1
Resale	1977/1979	-2.4	-11.0

Source: Ex. BE-1, Table I, p. 136.

appliances (such as residential and commercial air-conditioners) and the increased use of computerized energy management systems in commercial buildings.

J. Conclusions

Two major conclusions result from the preceding analysis of the Company's long-range demand forecast. First, the Council applauds the Company's achievements in its development of both a sophisticated and credible demand forecasting methodology. The above mentioned concerns and shortcomings notwithstanding, the overall effort is commendable and the Company and its forecasting staff should be proud of their accomplishment. The methodology compares quite favorably with those of other Massachusetts utilities of similar size and with similar resources. In many respects the Company's approaches are innovative and "state-of-the-art".

The second conclusion concerns data. The Company is not alone in that the quality of its data falls short of that of its methodology. This problem has plagued all the regulated companies in the Commonwealth. The Council therefore proposes that the Company temporarily back off from further enhancements to its methodology -- except for those efforts that are currently being pursued -- and allocate a greater proportion of its staff's time and resources to territory and sector specific data collection and analysis. In addition to the various sectoral surveys that the Company has committed itself to implementing, the Company should also: (1) avail itself of pending 1980 U.S. Census results; (2) assimilate, where appropriate, the load research requirements of PURPA Section 133 with EFSC forecast filings; and (3) acquire and utilize "Mass Save" audit data as a limited

d

cross-check in identifying trends within the residential sector. It is the Council's opinion that resources committed for prudent and comprehensive planning are miniscule compared to the potential cost of planning errors.

The Council wants to see continued progress in the Company's forecast methodology and particularly, its data collection efforts. Such progress has and can continue to be achieved through professional review, comment and rebuttal between the Company, the Council and intervenors.

The demand forecast and forecasting methodology is hereby APPROVED without conditions.

d

III. ANALYSIS OF THE SUPPLY PLAN

This review of the Boston Edison supply situation examines three aspects of supply. The review is in keeping with the Council's statutory mandate to examine whether long-range forecasts assure that regulated utilities can "provide a necessary power supply for the Commonwealth with a minimum impact on the environment at the lowest cost." (M.G.L. c. 164, 69H). The adequacy of supply is the Company's ability to provide sufficient capacity for its load throughout the forecast period. The diversity of supply is a measure of the mix of energy sources used. The Council's working hypothesis is that a more diverse supply mix, like a diversified financial portfolio, is less risky. Of course, reducing risk has its costs. The Council is also concerned with minimizing the cost of supply, subject to tradeoffs with adequacy and diversity.

A. Adequacy of Supply

Boston Edison has steadily reduced its projections of demand from the high level indicated in its First Forecast in 1976. (See Table 2, infra). The 1976 First Forecast projected an annual growth rate in peak demand of 5.45% and a 1985 peak of 3475 MW. The 1981 Second Forecast projects an annual growth rate for peak demand of 1.7% and a 1985 peak of only 2217 MW. (Boston Edison, First Forecast, April 30, 1976, Table E-17; Ex. BE-2, Second Forecast Volume 2, Table E-17). With demand projections lowered so dramatically, the need for new capacity has diminished.

The most significant event in the Company's supply planning over the last several years was its September 24, 1981 cancellation of the proposed Pilgrim 2 nuclear plant. If constructed on schedule, Pilgrim 2 would have increased the Company's net capacity from 2775 to 3532

d

megawatts, up 27%, in 1987. (Ex. BE-2, Forecast Vol. II, Table E-17). The cancellation of Pilgrim 2, which occurred after the submission of BECo's Second Forecast, requires the Council to examine the need for new capacity or other supply options to meet anticipated demand.

The Company's most recent projections of demand and supply show the system would fall below BECo's recommended reserve margin of 18%, to 15.4%, in the summer of 1990 (Table 5).[14] According to Company witness Cameron Daley, if the Company adds no new generation sources other than those for which it has signed contracts, and if the Company realizes its forecasted load growth of 1.7% per year, it would need new capacity by the end of the period.[15] If the forecasted load growth is realized, it is "already too late" to begin the process of licensing and construction of a new plant for 1990 operation, according to Cameron Daley. (Tr. Vol. III, pp. 19-20).

In recognition of the situation, however, the Company has under way several supply initiatives. Individually or severally, the initiatives should enable the Company to meet its demand through and beyond the end of the forecast period. The balance of this section discusses the major uncertainties with these projects and with the overall adequacy of the Company's supply.

Projected demand for 1990 is the least certain element in the calculation. The Company forecasts that peak demand, which occurs in

---

14 The Company currently has a 25% reserve. All but 110MW of its firm 1990 capacity is already on line (Ex. BE-2, Table E-17).

15 By contrast, the Company told the Wall Street Journal it believes it "can get through this century without new capacity." William Bulkeley, "New Hampshire Agency Prods Utilities in Other States to Lift Stake in Seabrook," Wall Street Journal, Jan. 13, 1982, p. 10.

d

Table 5

Boston Edison Company

Projected Capacity and Demand, Summer 1990

Existing Generation Facilities Including Jointly Owned Units (a)	2723 MW
Planned and Proposed Facilities	10 MW
Capacity Purchases	141 MW
NET CAPACITY	2874 MW
PROJECTED PEAK LOAD	2490 MW
Reserve %	15.4%

Source: Ex. BE-15, Q. 30, Table E-17.

(a) Includes 100 MW from Point Lepreau. Does not include Pilgrim 2 or other possible capacity additions.

the summer, will grow from 2100 MW in 1980 to 2490 in 1990, or at a 1.7%/ year rate. A difference of plus or minus one-half percent per year in the growth rate would change projected 1990 demand by plus or minus 120 MW. This amount is as large as any one of the Company's new supply projects. For this reason, a demand management strategy to reduce the uncertainty in load growth may be beneficial to the Company and worthy of its consideration. An active demand management program would also serve to increase the diversity of the supply mix and to reduce costs. (See subsection (B), below).

The Company has contracted for 100 MW of firm capacity from the Point Lepreau 1 nuclear unit of the New Brunswick Electric Power Commission, subject to Canadian National Energy Board approval. The contract is scheduled to run through 1987, and is renewable at the option of the Company for three additional years. The Company has stated to the Council that adequate transmission capacity for wheeling of this power to its service area is assured (Tr. Vol. III, p. 13; Ex. BE-15, letter to Doris Pote, Department of Public Utilities, from James Lydon, Boston Edison, July 24, 1981, p. 3)

The Company is "entertaining plans to talk" with New Brunswick about the possibility of purchasing capacity from a planned Point Lepreau unit 2 (Tr. Vol. III, p. 13). The Company has right of first refusal to replace (but not add to) its initial 100 MW purchase from unit 1 with an equivalent purchase from unit 2, should New Brunswick offer unit 2 for sale (Ex. BE-15, Point Lepreau Unit Participation Agreement Between the New Brunswick Electric Power Commission and Boston Edison Company, p. 37).

The Company is a participant in NEPOOL plans for the importation of Canadian hydroelectric power. It expects to receive an initial share of of 80 MW of power in 1988, and perhaps 250 MW later. The Company will participate in the payment of transmission costs. (Tr. Vol. III, pp. 16-18). Two companies have filed applications to construct the New England portion of the transmission tie-in. [16] Several hurdles must be cleared before power begins to flow. The Canadian National Energy Board must approve exports; FERC must approve imports; New England utilities and Hydro Quebec must sign a final contract; and numerous state, local and federal agencies must approve the transmission corridor. It is also unclear whether the Canadian power could be counted as firm summer capacity for BECo.

The Company is considering the purchase of shares in the Millstone 3 project of Northeast Utilities, and the Seabrook 1 and 2 projects of Public Service Company of New Hampshire. The Company would seek to obtain approximately 300 MW of capacity from the several projects. Negotiations with the Companies involved have not yet begun. (Tr. Vol. III, pp. 18-19).

The Company has informed the Council that its participation in the above projects is subject to financial constraints. The power purchases could be stopped "because of our [BECo's] inability to forecast [its] financial resources based on the outcome of the currently pending rate

---

16 New England Electric Transmission Corporation is a subsidiary of the New England Electric System (NEES). It applied to the Public Utilities Commission of New Hampshire for a "Certificate of Site and Facility to Construct, Operate and Maintain an Electric Transmission Line" in Coos and Grafton Counties, New Hampshire, on November 12, 1981. The Vermont Electric Company has filed an application for a "Certificate of Public Good" with the Vermont Public Service Board under 10 V.S.A. section 248."

case". (Tr. Vol. III, p. 16).

According to Company witness Cameron Daley, if one assumes that the Company will complete its planned purchases, there would be sufficient capacity to meet forecasted load through approximately 1995 (Tr. Vol. III, p. 20). The Company could have adequate capacity until the end of the century with no new construction if load growth is lower and if Mystic Units 4-6 are converted to coal. According to Mr. Daley, conversion would prolong the useful lives of these units past their currently scheduled retirement date of 1995. (Tr. Vol. III, p. 23). The Company could, however, face a difficult situation by 1990-91 if load growth accelerates, if the Point Lepreau contract is not renewed, and if neither the Hydro Quebec nor New England nuclear purchases are realized. Table 6 projects hypothetical scenarios for 1990 demand. In the worst case, with no new supply additions, no renewal of the Point Lepreau contract, and greater than expected load growth, the Company could be 200-300 megawatts short of the level needed to meet an 18% reserve. Assuming, however, growth at the forecasted 1.7% per year, and new purchases from Canada, Millstone, and Seabrook, the Company would have reserve capacity of 150-400 MW above and beyond the 18% minimum. Indeed, if the Canadian hydro and Point Lepreau purchases can be completed, the prospective Seabrook and Millstone purchases may be unnecessary in the Forecast period.

Table 6

Boston Edison Company

Hypothetical Comparisons of BECo Peak Demand and Supply, 1990-91

		Optimistic Case	Worst Case
(1)	Summer 1990 net capacity	2874 MW	2874 MW
(2)	Plus: Canadian Hydro	80	--
(3)	Plus: Millstone and Seabrook purchases	300	--
(4)	less: Point Lepreau contract not renewed	- -	(100)
(5)	Total Capacity (1+2+3+4)	3254	2774
(6)	less allowance for 18% reserve	2758	2351
(7)	Load with slow growth (a)	2366	2366
(8)	Surplus (deficit) (6-7)	392	(15)
(9)	Load with accelerated growth (b)	2610	2610
(10)	Surplus (deficit) (6-9)	148	(259)

a - 1.2%/year growth, 1980-1990
b - 2.2%/year growth, 1980-1990

Sources: Ex. Be-15, Revised Table E-17; Ex. BE-1, Forecast Vol. I, Table E-11; Tr. Vol. III, p. 29; and EFSC calculations.

In conclusion, it is the opinion of the Council, given the supply initiatives now being pursued by the Company, that the cancellation of Pilgrim 2 will not jeopardize the Company's ability to meet its load during the Forecast period. Before the Pilgrim concellation, Company witness Paul Davis told the Council that the decision to build the plant "is not based on need for power. It is based primarily on oil backout and economics". (Tr. Vol. II p. 113). It is the expectation of the Council that a major new base-load facility will not be needed for capacity reasons within the forecast period. The Company should, however, diligently pursue the alternate supply options outlined above. Even if the "optimistic case" described in Table 6 is realized, and new capacity is not needed for supply adequacy, it may be needed to create a more diverse supply mix and to reduce or stabilize costs. A demand management strategy could be used to reduce the uncertainty in the Company's load growth; conservation and load management are supply options that can buy time.[17] The Council expects to see evidence that the Company is pursuing these options in its next filing.

B. Diversity and Cost of Supply

Diversity of generation sources in electric systems tends to minimize vulnerability to interruptions in fuel supplies, and to abrupt increases in the price of one fuel source.[19] Other factors being equal,

17 See MMWEC, 5 DOMSC 89-91 (1981) on load management.

18 Note that this use of the term "diversity" differs from the meaning it normally holds in the electric business, i.e. the coincidence of loads on the demand side.

the smaller a proportion of the generation mix that each supply source represents, the greater the potential stability and reliability of electricity supplies.

To the extent that diversity provides a hedge against future price increases, it tends also to reduce long-run costs. It may or may not reduce short-run costs, depending upon the mix and the current prices of each fuel. A utility may wish, however, to purchase a fuel source that costs somewhat more today if it contributes to increase diversity.

At present, the Company is heavily dependent upon one fuel source, oil. Sixty-eight percent of BECo's capacity is oil-burning (another seven percent, mostly peaking plants, can burn oil or gas). The balance of the Company's generation is nuclear (Calculated from Ex. BE-2, Forecast, Vol. II, Tables E-24 and E-12. Includes purchased capacity).

The lack of diversity in the Company's supply mix creates problems for its customers. Most importantly, oil is expensive, and so is Boston Edison electricity. For example, the fuel adjustment charge now in effect for the Company is 5.04 cents per kilowatt-hour. In comparison, that of Mass. Electric (which relies more heavily on coal) is 2.80 cents, 45% less; that of Western Mass. Electric (with substantial nuclear generation) is 2.90 cents/kwh.[19] The heavy dependence on oil makes Boston Edison's customers vulnerable to sharp oil price increases, and possibly to supply interruptions.

Both Federal and Massachusetts policies emphasize the need for

---

19 Boston Edison, Application for Approval of Revised Fuel Charge, Dec. 18, 1981, DPU 1009E; Massachusetts Electric, Standard Fuel Clause filing, First Quarter 1982, DPU 1001E; Western Mass. Electric, Quarterly Fuel Charge Rate, Quarter Commencing Dec. 1, 1981, DPU 1010C. Documents on file at the Massachusetts D.P.U.

backing out oil. The Council has repeatedly emphasized the importance of reducing utility company dependence on oil.[20]

The Council recognizes that Boston Edison's mix of generating plant is the product of business decisions of years past and that the cost and lead times involved with changing that mix limit the Company's ability to respond. The Company has taken a number of laudable initiatives. However, Boston Edison has made less progress in diversifying and in reducing the cost of its power than the other two largest electric companies in Massachusetts.[21] We now turn to a discussion of Boston Edison's initiatives.

---

20 See Eastern Utilities Associates, 5 DOMSC 10. 30-36 (1981), EFSC 79-33; Mass. Municipal Wholesale Electric Co., 5 DOMSC 53, 84-89 (1981), EFSC 79-1; and Mass. Electric Company et al, 5 DOMSC 97, 118-124 (1981), EFSC 80-24.

21 Western Massachusetts Electric and Massachusetts Electric are the other two of the Commonwealth's three largest electric utilities. Both have moved aggressively to diversify their generation mixes. Mass. Electric has completed conversion to coal of three of the four units on Brayton Point, its station. It has completed feasibility studies and applied for permits to convert its Salem Harbor and South Street Units. Mass. Electric's supply plans are projected to reduce its capital costs by $2.6 billion between 1981 and 1996. Western Mass. Electric and its parent corporation, Northeast Utilities, are considering conversion of 859 MW of oil-fueled capacity by 1986.

The two utilities are moving in other new supply directions as well. Each expects to obtain approximately 200 MW of new capacity from renewable resources and from cogeneration between 1981 and 1990. This will allow them to "back out" oil directly, and to gain valuable experience in the purchase and development of alternative energy. Both companies have also proposed load management programs in order to reduce load growth and alter load shape in the most cost-effective manner. Mass. Electric plans rate incentives and a central control system.

The above figures come from Northeast Utilities, N.U. Conservation Program for the 1980's and 1990's, Jan. 1981; New England Electric System, NEESPLAN: First Update, Nov. 1980; New England Elec. System, (EFSC 81-24, Response to Information Requests.)

The Company has begun to explore the potential for conversion to coal of its Mystic and New Boston power plants. It has told the Council that it is currently analyzing conversion of Mystic Units 4-6, and of one of the base-loaded New Boston units. In May of 1981, the Company solicited proposals to convert Mystic Units 4-7. These proposals were to include all necessary services -- conceptual, architectural, engineering, environmental and construction. Sealed bids from six firms were received on June 22, 1981. BECo reported to the Council that a firm would be selected by "late Fall, 1981." However, its last report, dated December 21, 1981, indicates that the Company's timetable has been slipped substantially -- new bid specifications must be issued, some as late as April, 1982. (Ex. BE-19 and BE-20). The Company has also stated that conversion is dependent upon the outcome of its pending rate case before the Mass D.P.U. (Tr. Vol. III, p. 25).

Detailed engineering studies could determine that the cost of reconfiguring or reboilering units at Mystic and/or New Boston makes conversion uneconomic or technically impossible. Environmental restrictions could also stop conversion. However, it appears that an enormous savings in fuel costs can be reaped; the price differential in New England between coal and residual fuel oil has recently been $1.20 to $2.50 per million BTU, (or about 1 to 2 1/2 cents per kwh).[22] The potential savings in fuel costs for Mystic and New Boston are more than $100,000 per day of delay, assuming that the oil/coal price differential

---

22 Electrical Week fuel price reports, Oct. 5, 1981, Oct. 26, 1981, Nov. 2, 1981 and Dec. 21, 1981; "Oil backout plan gives break to customers Electrical World, Dec. 1981, p. 26.

will continue until after conversion can be completed.[23] This yawning price gap alone puts a burden on the Company to study and resolve the issue speedily. (See Condition 1 to the Decision, infra).

The Company is considering the use of natural gas at Mystic Unit 7 and at New Boston, and is negotiating with gas suppliers, according to Cameron Daley. Conversion of Mystic Unit 7 to dual-fuel capability (gas and oil) would be dependent upon availability of supplies in the market for natural gas. (Tr. Vol. III, pp. 27-28). A dual-fuel capability (coal and oil) would be retained at Mystic 4-6 if these units were converted to coal. The Council commends these proposals because they would reduce oil dependence while preserving the ability to revert to oil should shortages or dramatic price increases affect coal or gas supplies.

The company has considered the construction of either a combined-cycle coal-gas plant, or a low-BTU coal-gas plant at its Edgar Station site in Weymouth. The gas would be used at New Boston station to generate electricity. Boston Edison, with subcontractors British Gas Corporation and Stone and Webster Engineering Corporation, submitted a technical proposal dated September 30, 1980 to the Department of Energy for development funding, and was rejected. BECo retained Bechtel Power Corporation to solicit funding from the Synfuels Corporation to do an ongoing study of potential uses for Edgar Station. This was

23 The savings are calculated as follows. Mystic 4-6 and the smaller of the two New Boston units have a total capacity of 825 MW. If one takes the bottom end of the range of fuel savings estimates -- 1.05 cents/kwh -- and assumes a modest capacity factor of 60%, then savings per day are:
825 MW X 1000 KW/MW X 24 hrs X 1.05 cents/kwh = $104,000/day.
The daily savings are higher if one uses higher estimates of the fuel prices and capacity factor; at 1.5 cents/kwh and a 70% factor, savings would be $207,000/day.

unsuccessful. Boston Edison is not now spending any money on the project; its current strategy is to monitor the results of other research and demonstration projects. (Tr. Vol. III, pp. 51-2; Ex. BE-14, Q. S-2).

The Company's plans to purchase Canadian nuclear electricity and hydropower, and its intention to buy shares of the Millstone and Seabrook projects, are meaningful steps toward diversification. The Canadian imports, however, may not produce dramatic cost savings; Canada may be expected to price its power closer to the replacement costs of New England buyers than to its own cost of service. Also, prediction of the cost of nuclear power is hazardous, given the tremendous inflation in nuclear costs in the last decade, and public opposition.

With respect to cogeneration, the Company has done a preliminary survey of steam demand of 20 large customers. It has determined that only two have sufficient steam demand to cogenerate economically by themselves. (Ex. BE-14, Q. S-5; Ex. BE-15, Q. 15 and 16). Boston Edison has a long-standing arrangement to purchase electricity from one of the two, Atlantic Gelatin. It has not made a similar arrangement with the other, Gillette, which has a plant in Boston. The Company projects that no new cogeneration capacity in its service territory will be developed during the forecast period. (Ibid, and Tr. Vol. III, pp. 33-37). The Company has responded to several inquiries by potential cogenerators but has not explored the potential for joint cogeneration facilities for two or more customers.

Boston Edison has provided engineering support to small hydroelectric developers, and has screened potential sites in its service territory. No economic sites have been found. Unlike some utilities, the Company has not looked for sites outside its service territory (Ex. BE-14, Q. S-5; Ex. Be-15, Q. 17-18; Ex. AG-Sl, Q. 7-8).

BECo cooperated with the Department of Energy (DOE) in placing an experimental wind machine on Moon Island in Boston Harbor. The Company has not advanced its own funds to make necessary repairs to the machine (Ex. BE-14, Q. S-5; Ex. BE-15, Q. 19). The Company has scrapped plans for an experimental fuel cell power plant. (Tr. Vol. III, p. 32).

BECo is cooperating with Wheelabrator-Frye Corporation of New Hampshire on a trash-to-energy project. The proposed facility was designed with DOE development funds. It would produce steam only, for the BECo steam system, and will be built if a Boston urban site can be located and approved. (Tr. Vol. III, p. 30-31; Ex. BE-14, Q. S-5; AG-Sl, Q. 11).

The Company's service territory is less favorable for development of these so-called "alternate energy technologies" than are some other service territories in the Commonwealth. There are fewer potential hydroelectric sites, and less of the heavy industry that is a prime candidate for cogeneration. The Company has stated that it has found a number of hydro, wind, and cogeneration projects to be uneconomical given current costs. (Ex. BE-14, Q. S-5; Ex. AG-Sl, Q. 7).

However, the state of the art in alternate energy technologies is advancing. This, plus future shifts in the cost of oil, gas, coal, and nuclear power may make some alternate technologies suddenly very attractive. If Boston Edison begins now to work with alternative energy developers or to develop such projects itself, it will develop an "in-house" institutional capability which may serve it well in the future.

The Company currently has underway several experiments in demand management and conservation. These efforts can contribute to meeting the goals of diversity and minimal cost, as well as to help insure an adequate supply, as discussed in subsection (A) above. BECo has initiated a double-billing experiment for large commercial and industrial customers in the "T" and "TA" rate classes, and has approximately 200 residential customers on voluntary time-of-use rates (Ex. BE-15, Q 13). The Company has noted, however, that these experiments, though necessary, tell relatively little about the possible effects on customer usage of mandatory time-of-use rates (Ibid, attachments). The Company has performed experiments with a power-line carrier communication system, a load management technology. (Ex. BE-14, Q. S-11). It is testing, and may promote, controlled water heaters. It plans to market heat pumps, which could create a winter needle-peaking problem [24] (Tr. Vol. III, pp. 40-42). The Company is on the record as favoring load management, though it has not developed plans to do so: "If and when time-of-use rates are mandated [by the Department of Public Utilities], the Company tentatively plans to analyze such consumer responses as conservation, load shifting, load reduction and elasticity effects as appropriate." (Ex. BE-15, Q. 14).

The Company has several conservation information and publicity programs underway. The Council is pleased to see these efforts, and

---

24 The Company should examine the impact of new home heat technologies on its load, particularly dual-fuel technologies such as the gas-electric heat pump.

hopes that the Company will press forward with these initiatives.[25] Two of 33 commercial sector field representatives are available to discuss energy conservation. The Company participates in Mass SAVE, a residential audit program. (Ex. BE-15, Q. 10, Q. 13).

Boston Edison has underway a commercial sector customer survey. At the hearing in November, 1981, the Company's witness was unaware of any plans to use the survey results to study or implement demand management services in its commercial sector. (Tr. Vol. III, pp. 46-47). However, at the Council meeting on February 8, 1982, the Company agreed to analyze the survey results, to evaluate various options it might offer its commercial customers, and to propose a conservation and load management program which would conform to appropriate cost effectiveness standards. See condition 2, infra.

The potential for controlling overall load growth is large, particularly in the commercial sector.[26] The BECo service territory's commercial sector comprises 43% of its energy demand. Forty-seven percent of projected growth in kwh sales over the forecast period is in the commercial sector. (calculated from Ex. BE-1, Forecast Vol. I, Table E-8).

---

25 The Company has provided the Council with an extensive list of information programs that it has underway or is considering implementing (Ex. BE-17).

26 The Council has not relied upon data outside Boston Edison's service territory to reach this conclusion, but a study done for another electric company illustrates the potential for controlling load growth. A survey of the commercial sector in the service territory of New England Electric found that consumption could be by 10-20% in new and existing structures with paybacks of just a few years; NEES is currently evaluating ways to control energy growth by providing energy management services (See Xenergy, Inc., Final Report on the Development of an Energy End Use Data Base for the Commercial sector services by the Retail Subsidaries of the New New England System in Rhode Island and Massachusetts, Sept. 1981).

The Company is failing to serve the best interests of its customers if it does not explore the extent to which it can reduce system costs by a program of active demand management. There is a pressing need for the Company to develop baseline data on its commercial customers, and to use that data to develop a business plan for active load management and conservation. The Company may best be served by bringing in outside expertise for these tasks. (See Condition 2, *infra*).

In summary, Boston Edison is taking some admirable steps toward oil backout. If its current plans are realized, it will add several hundred megawatts of nuclear and hydro capacity during the forecast period. These steps will increase the diversity of its supply mix and help to stabilize electricity costs. The Company is not moving as quickly as it should in its analysis of coal conversion at Mystic Units 4-6, nor has it made much progress in developing renewables and cogeneration. It has taken only very limited steps to manage its demand; it apparently does not view such management as a way to increase diversity and minimize costs. In an era when Boston is experiencing major hotel and commercial construction, the omission of a demand strategy could be a serious error.

IV FORECAST DECISION

The Second Forecast of Boston Edison is APPROVED. The demand forecast is approved unconditionally. The supply plan is approved subject to the following conditions:

1. That the Comapny make available to the Council Staff on a confidential and proprietary basis a copy of the winning firm's proposal to study coal conversion at Mystic Units

4-6 and New Boston as soon as the Company makes its choice. The Company should provide its next "status report" in April, 1982 and monthly thereafter".

2. That the Comapny continue its current data collection efforts as part of an effort to determine how electricity is and will be used by existing and new customers in the commercial sector. It should evaluate information services, rate incentives, technical assistance, and financial incentives which it might offer to its commercial customers as part of a comprehensive conservation and load management program. The Company should describe its process of evaluation, report its results, and propose a demand management program utilizing those measures which conform to appropriate cost-effectiveness standards as established by the Company, as part of its next filing with the Council.

3. It is further ordered that the Company submit its First Supplement to the Second Forecast by September 1, 1982.

by Robert T. Smart Jr.

Robert T. Smart Jr., Esq.
Hearing Officer

on the decision:
Jeff Brown
John Hughes
Ronald Lanoue

This Decision was approved unanimously by the Energy Facilities Siting Council at its meeting on February 8, 1982 by those members present and voting. Voting in Favor: Margaret St. Clair, Richard A. Croteau, George Wislocki, Thomas J. Crowley, Harit Majmudar. Abstaining: Ganson Taggart.

March 2, 1982
Date

M. A. St. Clair
Margaret St. Clair
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

Petition of the Commonwealth Gas Company (New Bedford Gas and Edison Light Company, EFSC 80-7, has been merged herewith) for Approval of Its Fourth Annual Supplement to Its Long-Range Gas Forecast	EFSC 80-5

FINAL DECISION (December 30, 1981)

This Decision approves the Fourth Annual Supplement of the Commonwealth Gas Company, subject to certain conditions. It is divided into four sections. The first section contains a procedural history. The second section describes and reviews the Company's sendout forecast. The third section evaluates the adequacy of the Company's supply plan. The fourth section contains the Order approving the Supplement and conditions thereto.

I. INTRODUCTION

The Commonwealth Gas Company and the New Bedford Gas and Edison Light Company filed their Fourth Supplements to their May 1976 forecasts, separately, on December 4, 1981. No new facilities, as defined in G.O. Ch. 164 sec. 69G, were proposed for adjudication.

The Companies gave proper notice of these adjudicatory proceedings by publication in local newspapers and posting at the city and town halls. A pre-hearing conference was held at the EFSC offices on March 5, 1981. The Attorney General was allowed to intervene; no other persons requested intervenor status. The Attorney General did not participate actively in these proceedings.

New Bedford Gas and Edison Light Company was merged into Commonwealth Gas Company in January of 1981. As a result of this merger, the Hearing Officer issued a Procedural Order on October 2, 1981 consolidating the review of the two companies' filings, EFSC 80-5 (Commonwealth) and EFSC 80-7 (New Bedford). The consolidated proceeding is a review of the Commonwealth filing and is docketed as EFSC 80-5. The two merged Companies will, for the balance of this Decision, be referred to as the "Company" or "Commonwealth."

Thirty-three information requests were sent to the Company on October 2, 1981. Answers in writing were not required. Rather, they served as an agenda for a "technical session" held at the EFSC office on October 20, 1981, which narrowed the scope of issues considerably. Five information requests were ultimately sent; written answers were provided by the Company on November 24, 1981.

The Staff reviewed the written materials in the Docket and recommended to the Hearing Officer that the Staff prepare a Tentative Decision for the Council's consideration without a formal evidentiary hearing. After obtaining the assent of counsel for the Company, the Hearing Officer established a written record by Procedural Order dated December 7, 1981.

II. SENDOUT FORECAST

The Council employs three criteria in its evaluation of gas utility forecasts.[1] A forecast is reviewable if a Company's sub-

1 See 4 DOMSC, EFSC 79-5, Commonwealth Gas Co., 11 August 1980.

mittal to the Council contains enough information to allow a full understanding of the Company's methodology. Once this threshold of documentation has been crossed, the Council examines whether a forecast is appropriate, or technically suitable for the utility system. A forecast is further judged reliable if it provides confidence that the assumptions, judgements, and data forecast what is most likely to occur. This sendout forecast section of the decision reviews the Company's submittal in light of each criterion in turn.

The Council's decision in the review of the Companies' Third Supplement[2] focused upon the reviewability of the forecast. The Council found that the Company had not fully documented its forecast methodology. The Company had not explained:

- how forecast sendout was divided between heating and non-heating seasons (EFSC 79-5, p. 5);
- what heating increments were used to forecast design year sendout, or how these increments were estimated (p. 6);
- what factors were used to forecast peak day sendout, and how they were estimated (p. 6);
- how the Company determined its estimates of conservation and additional sales (p. 7); nor
- how the Company estimated heating increment and base use (p. 8).

2 ibid. The decision reviewing the filing of the New Bedford Gas and Edison Light Company (4 DOMSC, EFSC 79-7), 11 August 1980, was virtually identical to the Commonwealth decision. Hereafter the word "Company" refers to both Commonwealth and New Bedford.

The Council was of the opinion that the forecast was not reviewable, absent this information.

The Council attached to the forecast approval several conditions. The Company was required to explain the bases of significant judgements (Condition 1, EFSC 79-5); explain how additional sales are forecast (Condition 2); and state the factors used in estimating base use and heating increment, and these factors' bases (Condition 4).[3]

The Company has complied substantially with these conditions in its Fourth Supplement. The forecast of the Company now meets the Council's criterion of reviewability. The Council lauds the Company's progress and cooperation.

The Council decision further stated that: "Comments concerning the appropriateness and reliability of the forecast will be reserved for a later Council decision."[4] The discussion which follows will therefore focus on whether the forecast is appropriate and reliable.

The Company prepares its forecast in several steps. It forecasts normal year base use and heating use by customer class separately from normal year aggregate use. Design year and peak day sendout are the product of a third process. Adjustments for conservation and market expansion are made to each part of the forecast.

The Company forecasts normal year use by customer class as follows. It calculates July and August use for the previous sea-

---

3 The same conditions were attached to both EFSC 79-5 and 79-7.

4 4 DOMSC, EFSC 79-5, 11 August 1980, p. 7.

son by each customer class, counting this as base use. It applies to July-August use a set of "base use factors" that determine base use sendout by month.[5] Total use in the previous heating season, less base use, equals heating use. These data are then used to break the Company's forecast of aggregate sendout into forecasts by customer class.

Aggregate sendout is forecast separately. The Company calculates monthly factors that represent the total sendout per degree day per month in the previous heating season.[6] It multiplies these monthly factors by the number of degree days in a normal year to estimate heating season use in a normal year.

Forecast of firm sendout in future years is based upon two adjustments to the normalized normal year data. First the Company forecasts the number of new customers that can be added, and the projected use per customer. The consumption is added to the forecasted amount. Second, the Company subtracts a conservation increment of 1% per year from all firm sales.

The Company has also developed normalization factors for design years and for peak days. These are applied to degree day forecasts in order to develop design year and peak day estimates.

In summation, the Company's sendout forecast method relies upon estimates of several critical variables:

---

5 Base use is usage other than space heating and includes primarily water heating and cooking. Base use increases in winter, primarily bacause more energy is needed to heat cold water in winter than warmer water in summer.

6 Note that the forecast of aggregate sendout does not depend on the base use factors, since the Company forecasts total sendout, not just heating sendout.

- monthly base use factors;
- normalization factors for normal years;
- normalization factors for design year and peak days;
- additional firm sales;
- conservation increment; and
- peak and design weather conditions.

It is the opinion of the Council that the Company's methodology is appropriate for its system. Reliable estimates of the six key sets of variables would be sufficient to produce a reliable forecast; the methodology is suitable for the problems of managing the Commonwealth Gas system. The method might be improved in several ways; the Company could forecast sendout by customer class, and could separate heating and base use normalization factors. However, this is not absolutely necessary to produce a reliable forecast.

The reliability of the Company's forecast is a function of the reliability of the six key variables. Those variables are now each examined in turn.

Monthly base use factors are derived from a 1957 H. Zinder and Associates study of four Midwest and Middle Atlantic gas companies.[7] The Zinder factors are for residential cooking and water heating use. The Company has not demonstrated these residential sector factors developed 24 years ago for systems in other parts of the nation are applicable to today's use in all customer classes of the Commonwealth Gas system.

---

7 H. Zinder and Associates, Gas and Electric Service in Multiple Housing, December 1957, p. 41.

The normalization factors for normal seasons are calculated each year from actual sendout and degree day data. This inspires a measure of confidence in these factors.[8] Unfortunately, the Company does not maintain an historical record of such factors from year to year.[9] There is thus no way to judge retrospectively the accuracy of such factors, nor to establish their variability from year to year.[10] The keeping of such a record is a first step toward determining the reliability of the factors.

The design year normalization factors and peak day normalization factors are based upon judgement. The Company adds "judgement factors" to the normal year normalization factors to estimate the two former factors.[11] The depth of experience of the Company's Chief forecaster lends considerable weight to these judgements. However, the factors are vulnerable on two counts. Fist, the change in natural gas use per degree day as a function of temperature is a key behavioral concern. Customer behavior may change from year to year, and from month to month. An empirical investigation of behavioral trends would build confidence in the judgement factors.[12] Second, the design and peak

---

8 The Company uses linear regression to derive the monthly factors. The Company provided the Council with data from which one factor was calculated, 14 days of sendout statistics from January 1980 (response to Information Request 2, November 23, 1981). A Council estimation of the regression equation showed a respectable fit to the data, with a R^2 of .91.

9 Response to Information Request 2.

10 Future sendout forecasts are dependent on these factors, as modified by conservation increment. If the estimated factors vary significantly each year, then the reliability of the forecast is questionable.

11 Response to Information Request 3.

12 Such a study would build confidence in the normal year factors also

factors are linear functions of the normal year factors. If the normal year factors are not reliable, the design and peak factors will be questionable also.

To some extent, the Company can determine the number of customers added through policies on new hookups and conversions. Therefore, the Company can attempt to match actual with forecasted additional firm sales. However, the correlation is not automatic, as a comparison of 1980-81 forecasted and actual additional sales indicates (Table 1). The Company has firm plans for a 1982 survey of the potential market for gas conversions,[13] and has monitored actual sendout to new customers. The Council recognizes the inherent difficulty of forecasting customer additions, and supports the Company's plans to perform market research.

The Company's estimate of the conservation increment of 1% per year is based upon judgement. It is based first on an American Gas Association projection, and second on a assumption that high-cost conservation measures could save 20% and would take 20 years to implement.[14] The Council stated in its last decision: "The Council also notes that for the third largest gas company in the Commonwealth, judgement alone may be an insufficient basis upon which to reflect future conservation in a forecast."[15]

The Council would have more confidence in the estimate if it were based on service territory-specific data on both the technical potential for further conservation, and also on the level of

---

13. Response to Information Request 4.

14 Response to Information Request 1.

15 4 DOMSC, EFSC 79-5, 11 August 1980, pp. 7-8.

Table 1 Commonwealth Gas Forecasted vs. Actual Additional Sales, 1980-81

	Number of New Customers		Sendout/Customer	
	Forecast	Actual	Forecast	Estimated Actual Use
Residential	8400	6468	160 MCF	160 MCF
Commercial	620	484	1700	437
Industrial	12	51	1800	4490

Sources: Commonwealth Gas Fourth Supplement, November 1980, p. 3; Response to Information Request 5(a).

conservation retrofit activity actually occurring. The Company's planned 1982 market survey may provide an occasion to gather such data.

The Council also suggests that the Company consider producing two estimates of conservation. The first estimate, based on the AGA report and data the Company may develop, would forecast the level of conservation actually expected to occur. The second estimate would be a lower number that represented the amount of conservation which the Company could count on for the purpose of planning additions of new sendout. With such a forecasting procedure, the tension between developing an accurate conservation forecast and a prudent forecast would be resolved.

Though the Council does not believe that the Company's overall methodology produces any inherent biases in its estimates of sendout, it does note several forecast anomalies that the method produces and that point up the issue of the reliability of the forecast. The Company projects conservation of 1% per year in each customer class. The AGA study upon which the Company relies for its conservation estimates forecasts greater conservation in the residential sector (1.2%) than in the commercial (0.4%) and industrial (0.8%) sectors.[16] Among residential customers without gas heat, the Company forecasts 1%/year conservation, even though consumption per non-heating customer has <u>increased</u> in each of the last four years at an annual rate of 1.6% per year. The methodology produces a jump in split-year heating use per customer per degree day from .0143 MCF to .0148 MCF between 1979-80 (the last

16 Response to Information Request 1.

year for which actual data exist), and 1980-81 (the first forecasted year).[17]

The design year and peak day degree day estimates were defined as the coldest in the last 25 years.[18] The peak day maximum was however exceeded last winter by one degree. The Company may wish to revise accordingly its peak day estimate.

In sum, the Council believes that the Company's estimates of its six key variables are less reliable than the Company is capable of producing. The reliability of the forecast could be improved through development of company-specific data on customer usage patterns on conservation activity, on variability of sendout per degree day, and other behavioral questions as noted above. The urgency with which the Company should approach the task of data development is intimately related to the adequacy of supply. If a Company has a relatively large surplus of supplies over expected sendout, the Company can tolerate more uncertainty in the sendout forecast than it could if it were operating on a thinner margin of supply.

III. SUPPLY

Of concern to the Council is the ability of companies to provide adequate supplies of gas at the lowest possible cost. This section of the decision reviews the Company's supply situation,

17 Fourth Supplement, November 1980, Table G-1, Table G-22.

18 A statistical test of the Company's degree-day data since 1950 by the Council staff indicates that the Company's design year of 7300 degree days has a probability of occurrence of approximatley 1%, or one year in one hundred.

and the interaction of supply issues with sendout forecast issues. The supply issues are broken into the following categories: forecast period supply, heating season supply, peak day supply, "cold snap" supply, conservation programs, and supply summary.

A. Forecast Period Supply of Pipeline Gas

Like all gas companies in the Commonwealth, Commonwealth Gas is dependent principally upon pipeline supplies from Texas and Louisiana. The Company has little if any leverage in the market for gas supplies; it is dependent upon the pipeline companies and upon the Federal Energy Regulatory Commission (FERC) for obtaining stable supplies.

Adequacy of future gas supplies from the pipelines is a major concern, for gas utilities and consumers throughout the Northeast, as well as for those in Massachusetts, including Commonwealth. Several forecasts suggest declining pipeline supplies in the 1980's.[19] The Company forecasts that there will be no curtailments in contracted pipeline supplies in the forecast period: "This assumption is based on the best judgement of company personnel after considering the history of recent years, discussions with our suppliers, and informed con-

19 The gas utilities involved in the Boundary Gas project, (including several Massachusetts companies) project that their pipeline supplies will decrease from just over 620 billion cubic feet per year in 1981 to under 550 BCF in 1985 and under 450 BCF in 1990 (Application of Boundary Gas, Inc. for Authorization to Import Natural Gas from Canada, Appendix G, Dec. 1980, ERA Docket 81-04-NG). ICF Incorporated's natural gas forecasting model predicts that domestic US production will decline f om 18.6 trillion cubic feet (TCF) in 1981 to between 16.5 and 18.1 TCF in 1985 and 16.2-17.6 in 1990, depending upon Congressional action on price decontrol (Steven Muzzo, ICF Incorporated, "The Effects of Natural Gas Decontrol Policy Options on Future Domestic Gas Supplies", presented to IAEE Conference, Nov. 12-13, 1981).

tacts with the industry."[20]

Settling upon one forecast of future pipeline supplies for planning purposes is perhaps the most important issue facing all gas utilities in the Commonwealth. Commonwealth Gas is no more vulnerable to pipeline curtailments than are other companies. Since the Company's and other companies' ability to meet customers' needs throughout the decade depends on the pipelines, the Council is of the opinion that all companies should consider contingency plans that include variations in the timing and volume of pipeline curtailments.

B. Heating Season Supply

Commonwealth Gas, like other Companies in the Commonwealth, it also dependent upon supplemental gas supplies to meet heating season needs. The adequacy of supplementals is critical to heating season planning.

The Company is in a special position with regard to supplemental supplies. Its corporate parent is part owner of the Hopkinton LNG Corporation, a subsidiary whose primary business is liquefaction, storage and sale of pipeline supplies for Commonwealth Gas. The Hopkinton facilities are capable of storing 3500 MCF of gas, or 15% of normal heating season sendout.

Commonwealth also holds an Algonquin SNG contract for 3247 MMCF per year. During the forecast period, it expects that it

---

20 Forecast, Section 1, p. 1.

will need to draw only 2400 per year.

With these resources, in the last forecast year (1984-85) the Company could meet a heating season sendout 3.0% greater than expected design sendout by drawing additional SNG.[21] Since some of the heating season use is base use that is independent of temperature, the Company could survive a winter that is even more than 3.0% colder than the coldest winter of the last 25.

The accuracy of these reserve margins depends upon the reliability of the Company's forecast, especially the reliability of the estimate of 1% per year conservation; the availability of anticipated pipeline supplies; and the Company's policy with regard to new hookups and space heat conversions. The Company would run into difficulty in meeting demand if either the sendout forecast were an underestimate and the Company did not adjust its marketing plans accordingly, or if pipeline curtailments are experienced.

C. Peak Day Supply

The Hopkinton facility provides Commonwealth a large cushion for peak day requirements. At full daily capacity, Hopkinton could send out 270 MMCF per day, and thereby meet 89% of total peak day sendout.[22]

The Company is not dependent upon day-to-day deliveries of propane during the heating season. However, it does have avail-

---

21 If one does not count the 200 MMCF of propane supplies which the Company lists, then the 1984-85 reserve counting the SNG is 2.2%. Calculated from Forecast, EFSC 80-5 and 80-7, (Tables G-22(B).

22 Company contingency plans call for Hopkinton to have available 130 MMCF of vaporization capability, or 43% of forecasted peak day sendout.

able two additional propane facilities with a total capacity of 21.6 MMCF/day and approximately 2 days' onsite storage each. When added to firm pipeline commitments and to the Hopkinton capacity, there is no doubt as the ability of the Company to meet peak day requirements.[23]

D. "Cold Snap" supply

A "cold snap" is a series of peak like days, such as the two to three week period experienced during the winter 1980-81. Such periods present particular planning problems for gas utilities different from meeting needs on one extremely cold peak day, or meeting the needs of an entire heating season.

The Hopkinton facility provides Commonwealth with substantial capacity to meet sendout requirements during such a cold snap. The Company is not dependent upon day to day deliveries of propane supplies, and may have more than adequate reserves for its own needs.[24] The Company has been a consistent seller of supplies to other firms during peak sendout conditions. Last winter the Company sold 248 MMCF to other gas utilities during January and February.[25]

---

23 The Company projects an excess of peak day capacity over projected sendouts of 9% in 1980-81, and of over 3% in 1984-85, even with Hopkinton sendouts at 130 MMCF/day rather than the facilities' design capacity of 270 MMCF/day. The company retired three propane facilities in 1979, stating that the facilities were unnecessary.

24 At the extreme, if Hopkinton were close to full at the beginning of a cold snap, and were operated at normal sendout of 130 MMCF per day, it could provide two-fifths of the Company's needs for over three weeks.

25 Response to Information Request 5(b), Attachment 5 (b)-1.

E. Demand Management Programs

The one area of supply planning which the Company has not actively pursued is demand management through conservation programs. Gas utilities in California, Wisconsin and New York are investing in conservation devices in customers' homes; the "Conservation gas" those investments produce is comparable to new supplies of pipeline or supplemental supplies, and is much less costly than such supplies. Such programs have been found to benefit company stockholders as well as gas customers.[26] In New England, Northeast Utilities provides grants to its gas customers who install high-cost conservation measures (such as insulation and storm windows), and will install several low-cost measures itself for a nominal fee.[27] Governor King's Program to stabilize Utility Costs suggests that utility companies consider implementation of a program of modest (15%) grants for high-cost conservation measures, and subsidized installation of low-cost measures.

The Council recognizes that the advisability of a grant and installation program is dependent upon the particular cost, supply, and dispatch conditions of each gas system and of the ser-

---

26 See Decision 92653, Application 59737, before the Public Utilities Commission of the State of California, Application of Pacific Gas and Electric Company for authority, among other things, to implement a Conservation Financing Program, January 28, 1981; Public Service Commission of Wisconsin, Decision 05-GV-2, Class A Gas Utilities Residential Insulation Program, March 31, 1977; New York State Public Service Commission, Second Annual Report on Implementation of the New York State Home Insulation and Energy Conservation Act Program, January 31, 1980.

27 EFSC 81-17, Northeast Utilities, Long-Range Forecast, April 1, 1981, "Northeast Utilities Conservation Program for the 1980's and 1990's," pp. 41-46.

vice area's customers. Therefore, the Council's opinion is that the Company should explore the appropriateness of such demand management strategies for its particular system. The strategy to be examined may include efficiency standards for new customers, and greater incentives (including financial incentives) for existing customers to save gas. Although the Company's ability to implement some such strategies may be constrained by regulation, its ability to identify wise corporate strategies and ask the Council, the Department of Public Utilities, and the General Court for permission is not constrained. The Council staff will be available to assist the Company in analyzing different conservation approaches.

F. Supply Summary

It is the judgement of the Council that there is no need for the Company to adjust its current supply plans in light of its forecast of sendout and supply. The Company has managed its system prudently.

Furthermore, the adequacy of supplies during the forecast period make less urgent the task of increasing the reliability of the sendout forecast. The Company need not devote major resources to a crash forecasting project, but should recognize the need to make improvements in each successive forecast. Planning should be done for two major contingencies: pipeline curtailments and gas price decontrol.

The Company might create supply difficulties for itself by successfully marketing excessive numbers of conversions. This is however only a hypothetical problem. The Company has been very prudent in its new hookups policy, and most additions of new customers are made possible only by related savings of gas by existing customers. The Company is monitoring the level of conservation actually achieved; the Council anticipates that the Company will continue to do so, and will stand ready to modify its expansion plans should conditions ever warrant a change.[28]

IV. ORDER

The Fourth Supplement is APPROVED. The sendout forecast is found to be reviewable and appropriate. The Council notes a need to improve the forecast's reliability in the next few forecasts. Supply planning is found to be adequate for the forecast period. The Company should however investigate the use of demand management programs to insure that supplies remain adequate.

Forecast approval is subject to the following conditions:

1) That the Company begin to compile with the next forecast and in subsequent years a record of normalization factors which it calculates in the course of producing its forecast;

2) That the Company provide to the Council within ninety (90) days a response to the Council's evaluation of its sendout forecast methodology, and be prepared to hold a technical session with Council staff concerning this response. Such response should discuss the reliability of the base use, normal year, design year, and peak day normalization factors; the forecast of additions to load; and the forecast of customer conservation. The Company response should discuss what portions of the Council analysis it believes to be valid or invalid, and discuss Company plans to conduct research or

---

28 The Company has recently begun to require that heating contractors obtain a Company permit before hooking up new customers. The Company could use mechanisms such as this, and also changes in its promotional campaigns to modify the number of additions to its system, if limits to additions were needed.

otherwise improve those aspects of the methodology which the Company agrees need to be improved.

And it is further ordered that:

1) That the Company provide with its Second Forecast an evaluation of a demand management strategy that includes conservation grants and an installation service. The evaluation should discuss the cost-effectiveness of such a strategy to the Company and its ratepayers;

2) That the Company file its Second Forecast on July 1, 1982. Such filing should combine data from the former Commonwealth and New Bedford systems.

Energy Facilities Siting Council

by: Robert T. Smart Jr.

Robert T. Smart Jr., Esq.
Senior Counsel

on this decision:

Ronald A. Lanoue
Staff Economist

This decision was unanimously approved by those members present and voting at the Energy Facilities Siting Council meeting of December 21, 1981.

January 15, 1982
Date

M. N. St. Clair

Margaret N. St. Clair
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

Petition of the Cape Cod Gas Company for Approval of Its Fourth Annual Supplement to Its Long-Range Forecast, 1980-1985	EFSC No. 80-19

FINAL DECISION

This Decision APPROVES the Fourth Annual Supplement of the Cape Cod Gas Company, subject to the CONDITIONS attached hereto.

The first section contains an introduction and a procedural history. The second section describes and reviews the Company's sendout forecast. The third section describes and reviews the forecast of supplies. The fourth section discusses Cape Cod's contingency planning. The fifth section contains the Order and Conditions to next year's filing.

I. Introduction

Cape Cod Gas Company supplies gas to Wareham, Bourne, Sandwich, Falmouth, Mashpee, Barnstable, Yarmouth, Dennis, Brewster, Harwich, Chatham and Orleans. It is the twelfth largest gas company[1] in Massachusetts.

1 Until July 30, 1981 Colonial Gas Energy System was a holding Company which owned Lowell Gas Company and Cape Cod Gas Company and also owned Transgas Inc., which transports propane and LNG and other cryogenic gases. On that date Lowell Gas Company succeeded to the assets, liabilities and business of Colonial Gas Energy System pursuant to a reorganization in which Lowell Gas Company's name was changed to Colonial Gas Company. Colonial Gas Company now operates a Lowell Gas Company division and a Cape Cod Gas Company division and owns Transgas, Inc.

Cape Cod's annual gas sales are broken down by class as follows: residential with gas heating 63%, residential without gas heating 2%, commercial 29%. It has no industrial or interruptible customers. Cape Cod sells nearly twice as much gas in the heating season as in the non-heating season. The Company expects net annual increases of 890 customers in the residential heating class and 40 customers in the commercial class. Total gas sales are expected to increase by only 4.6% between the 1980-81 and 1984-85 split years. This is a 0.9% compound annual growth rate.

In its review of forecasts and supplements, the Council requires[2] each gas company to project "the gas requirements of its market area" over a five year period and to describe "actions planned to be taken by the Company which will affect capacity to meet such needs or requirements...", G.L. c. 164 section 69I. Under EFSC Rule 62.9(2), forecasts of sendout must be based upon historically accurate information and reasonable statistical projection methods. In its decisions in recent years, the Council has found statistical projection methods to be "reasonable" if they are reviewable, appropriate and reliable. A methodology is reviewable if it is clearly and thoroughly described, or documented, so that its results can be duplicated by another person given the same information. A methodology is appropriate when it is technically suitable for the size and nature of the particular system. It is reliable when it provides a measure of confidence that the assumptions, judgements and data which comprise it will forecast what is most likely to occur. A gas company must

2 For a more extensive discussion of the scope of and standard of review applied by the Council, See Boston Gas Company, EFSC 81-25.

demonstrate that it will have sufficient supply available to meet firm needs on an annual basis, during the heating season, and on peak days. It must also show that it is pursuing a "least cost" supply strategy.

The Cape Cod Gas Company filed its Fourth Annual Supplement to its 1976 Long-Range Forecast on November 3, 1980. That Supplement projected sendout and describes the Company's supply plan for the split years 1980-81 through 1984-85. No facilities were proposed for adjudication in the filing. A Tentative Decision was issued on December 22, 1980, but was withdrawn by a Siting Council vote at its meeting on January 20, 1981. The reason for the withdrawal was to give the Staff time to look carefully at the issues raised by the so-called "gas crisis" of January 1981 as they related to Cape Cod's supply planning for the forecast period.

The Company gave proper notice of this adjudicatory proceeding by publication in local newspapers and posting at the City and Town halls in its service territory. The Attorney General filed a Petition to Intervene on March 10th, 1981. A pre-hearing conference, attended by representatives for Cape Cod Gas Company and the Attorney General, was held on March 23. Cape Cod filed a written Opposition to the Attorney General's Petition on March 30th. After receipt of additional written materials from the parties, the Hearing Officer allowed the Attorney General to intervene on April 28, 1981. Discovery was completed in October of 1981. A Procedural Order on October 27, 1981 requested a list of witnesses and document responses from the Company, and a "statement of issues" from the Attorney General. It set a November 23, 1981 hearing date. The Attorney General filed a "Statement of Issues" on November 13, 1981. After requesting a postponement of the hearing, Cape Cod filed a "Motion to Strike Attorney General's Statement of Issues", which Motion was withdrawn after the parties reached agreement at a December 4, 1981 pre-hearing conference.

The hearing was held on December 8, 1981. No representative from the Attorney General's Office attended. Cape Cod offered into evidence its Fourth Supplement, EFSC Staff Information Requests and Company responses, extensive materials from the Massachusetts Department of Public Utilities investigation of last winter's "gas crisis" (D.P.U. Docket No. 555), and other documents pertaining to the Company's emergency procedures, conservation programs, and gas supply agreements. The Company provided two witnesses, F.L. Putnam, III, General Manager of the Cape Cod Gas Company, and Albert C. Dudley, Vice President of Gas Supply at the Colonial Gas Company, who answered questions from the EFSC Staff.

II. Forecast Methodology

A. Background

The Company's forecasts of sendout and supply have been reviewed annually by the Council since 1976. The methodology used in these forecasts has improved over the years and the Company has attempted to respond to the Conditions contained in the Council's previous decisions. The relevant conditions contained in EFSC 79-19 are:

1) That the Company explain in its next filing how the base use, heating increment, and average use factors used to prepare its forecast were derived, and the manner in which these factors are used to forecast sendout.

2) That the Company explain any judgements made concerning con-

servation, the basis for said judgements and the manner by which such judgements are incorporated into the forecast in the next filing.

3) That the Company state, and give the bases for, the average consumption factors used for each class to forecast peak day sendout in its next filing.

4) That the Company explain in the next filing the bases for its judgement that Algonquin Gas Transmission Company will have interruptible gas available and that there will be additional gas supply from Canada.

5) That the Company explain in its next filing what effect an immediate cessation of Algerian LNG deliveries will have on its LNG contract with the Bay State Gas Company. Specifically, how does the Company plan to meet each year's projected requirements under this circumstance.

The Company has provided the bulk of the information requested by the Council in these conditions. The Council appreciates the straightforward presentation of the material in the forecast and the manner in which the Company complied with the Conditions in the previous decision.

The following sections of this decision describe the Company's forecast in detail. Suggestions regarding improved forecasting techniques are provided to help the Company increase the usefulness of its forecast to the Council and the Company itself.

B. Forecast of Sendout

The Company's forecast of sendout includes forecasts of sendout by customer classification and a forecast of peak day sendout. Sendout for each customer class is first projected and then these forecasts are aggregated to achieve a system-wide forecast. The forecasts of sendout by customer class include forecasts of sendout to residential heating customers, residential non-heating customers and commercial customers. The Company has no industrial or interruptible customers. A breakdown of sendout by customer class for the 1981-82 and 1984-85 split years is presented in Table 1.

The methodology for forecasting sendout to residential heating customers (HC) and non-heating customers (NHC) can be summarized in the following equations:

$$Sendout_{HC} = (NCUST_{HC} \text{ X } BU/Cust) + (NCUST_{HC} \text{ X } HU/Cust/DD \text{ X } DD)$$

$$Sendout_{NHC} = NCUST_{NHC} \text{ X } NHUSE/Cust$$

Where: $NCUST_{HC}$ = Number of heating customers

$NCUST_{NHC}$ = Number of non-heating customers

BU/Cust = Base use per heating customer

HU/Cust/DD = Heating use per customer per degree day

NHUSE/Cust = Use per non-heating customer

Sendout in the Commercial class is forecasted in the same manner as sendout in the residential heating class. Base use and heating use are estimated separately.

Total sendout in a particular year is a function of the number of customers in the system in that year, the average gas consumption of these customers, and the weather. To achieve a forecast of sendout in the future each of these variables must be projected separately.

Table 1

Cape Cod Gas Company

Sendout by Customer Class
(MMCF)

	1981-82		1984-85	
	Heating Season	Non-Heating Season	Heating Season	Non-Heating Season
RESIDENTIAL				
Heating	2025(63)	1141(64)	2159(65)	1223(67)
Non-Heating	30(1)	71(4)	31(1)	71(4)
COMMERCIAL	805(25)	637(36)	782(24)	590(32)
COMPANY USE/UNACC.	346(11)	-58(-4)	355(10)	-58(-3)
TOTALS	3206	1791	3327	1825

NOTE: Numbers in parentheses denote percentage of total seasonal sendout.

The Company used a consistent approach in forecasting the variables included in the equations on page 6. The number of future customers in each customer class is assumed to be affected of the following significant determinants: population, the price of gas relative to alternative fuels, company advertising and promotion, and government policy. Local housing starts were examined as one indication of the number of new customers in the future. The usage factors (base use and heating use) in the residential and commercial classes were forecasted using historical data for each class. Five years of historical data was analyzed in each case. Trends in usage over the past five years were assumed to continue, but the rate of decline in residential use per customer is expected to be lower in the forecast period. Residential heating use per customer declined 6.8% between 1975-76 and 1979-80 on a weather-normalized basis. The Company forecasts a 3.8% decline over the five year forecast period assuming normal weather conditions. The historical and projected usage factors are presented in Table 2.

The Company's reliance on historical data to forecast future trends is of limited usefulness in today's rapidly changing energy marketplace. This is particularly true because the Company has made no attempt to relate changes in use per customer to the important factors driving these changes (such as the price of gas, customer awareness of energy conservation and the price and availability of fuels used in conjunction with gas such as wood and coal).

C. <u>Design Year Sendout</u>

In conformance with standard industry practice, the Company constructs two sets of forecasts: one under normal weather conditions and one under design conditions. Cape Cod uses the average number of

Table 2

Cape Cod Gas Company

Average Annual Use Per Customer[1]

	Residential Classes			Commercial Class[2]	
	Heating		Non-Heating		
	Base Use	Heating Use		Base Use	Heating Use
HISTORICAL					
1975-75	36.4	.0118	25.6	332	.0235
1976-77	37.3	.0117	23.3	320	--
1977-78	38.8	.0109	18.9	308	--
1978-79	37.3	.0103	18.5	296	--
1979-80	34.2	.0110	17.4	283	.0284
FORECAST					
1980-81	36.8	.0110	17.2	271	.025
1981-82	36.7	.0109	17.0	259	.025
1982-83	36.6	.0108	16.8	247	.025
1983-84	36.5	.0107	16.7	233	.025
1984-85	36.4	.0106	16.7	221	.025

---

1 Base Use figures expressed as MCF/year. Heating use figures expressed as MCF/degree day.

2 Historical data for the commercial class was incomplete. Base Use historical data was estimated by the Staff from the Company's explanation of a "straight line decrease of between 1.0 and 1.05 MCF per month per customer over the past five years." Historical heating use averaged .0275 MCF/DD over the past five years and this was used by the Company as a basis for their forecast of .025 MCF/DD during the forecast period.

degree days/year in the last 20 years to define normal weather. Design conditions are defined by the Company as the number of degree days during the coldest twelve month period of the past twenty.

The manner in which the Company estimates design year sendout is not adequately documented. The Company's design year is approximately 13% colder than the normal year. Total sendout in a design year is estimated by the Company as approximately 8.6% greater than normal in the heating season and 4.6% greater than normal in the non-heating season. Although these figures appear reasonable, the Company is directed to present its methodology for calculating design year sendout in its next forecast.

D. Peak Day Sendout

The Company uses a peak day consisting of seventy degree days. This is based on the coldest day experienced in the past fifteen years. Peak day sendout is calculated by multiplying the estimated future number of customers in each class by a peak day consumption factor for each class (the consumption factors are expressed as MCF/customer/DD).

The Company states the peak day consumption factors were estimated from historical sendout on peak days during the past five years. The Company's analysis indicates that peak day consumption factors have remained steady during the past five years; accordingly, the peak day consumption factor is assumed to be constant during the five year forecast period.

The Company's methodology raises an important question relevant to peak day sendout. The coldest days in the five years analyzed by the Company ranged from 57 DD to 66 DD (Ex. Cape Cod-1, Forecast Supplement, Table DD). It is unclear how the Company used sendout on these peak days to estimate sendout on the design peak day of 70 degree days. The Siting Council has received evidence in another proceeding[3] suggesting that heating use/DD rises as the number of degree days rise. This indicates that consumption factors based on days with 57 to 66 DD may be too low for a design day with 70 DD.

The Company is directed to provide adequate documentation of its peak day sendout forecast in its next filing, including an explanation of how use/customer/DD is affected by outside temperature. In addition, any historical peak day sendout data used by the Company in estimating peak day sendout during the forecast period must be included in the next filing.

III. Forecast of Supplies

A. Background

Like all other gas companies in the Commonwealth, Cape Cod relies on a diverse mix of supplies to provide gas to its customers. During the non-heating season, when demand is low, essentially all of the gas provided by the Company is natural gas transported from Texas and Louisiana. It is brought into the state by the Algonquin Gas Transmission Company's pipeline. During the heating season, the Company supplements these pipeline supplies with gas stored underground in New York and Pennsylvania, LNG, propane and SNG. Roughly 41% of Cape Cod's heating season supply is pipeline gas and 18% is gas stored underground. The remainder is LNG (27%), propane(5%) and SNG(8%). These figures are shown in Table 3 along with normal firm sendout of each of these

3. In re Lowell Gas 7 DOMSC _______, EFSC 80-16 (1981).

Table 3

Cape Cod Gas Company

Heating Season Supplies and Sendout
(MMCF)

	1981-82		1984-85	
	Total Supply Available	Normal Firm Sendout	Total Supply Available	Normal Firm Sendout
PIPELINE				
F-1	1250(33%)	1250(39%)	1165(31%)	1165(35%)
ST-1	692(18)	300(9)	601(16)	330(10)
WS-1	293(8)	293(9)	293(8)	293(9)
SNG-1	307(8)	307(10)	614(16)	614(18)
NON-PIPELINE				
Propane	204(5)	174(5)	380(10)	350(11)
LNG Storage	1007(27)	882(28)	727(19)	575(17)
TOTAL SUPPLY	3753(100%)	3206(100%)	3780(100%)	3327(100%)
DESIGN YEAR REQUIREMENTS	3484		3622	

NOTE: Algonquin SNG, Inc. offered Cape Cod and other SNG customers the option of reducing their take or pay obligations for SNG by approximately 50% during the 1981-82 heating season. Cape Cod accepted this options and substituted 225 MMBTU of LNG (purchased from Bay State Gas Company) in place of 307 MMBTU of SNG for the 1981-82 heating season.

supplies.

The following sections of this Decision discuss each of these supply sources in detail.

B. Pipeline Supplies

Cape Cod's forecast of supplies is based on the assumption that its firm contracts for pipeline supplies will be fulfilled by the Algonquin Gas Transmission Company. These contracts run until November, 1989. In addition, the Company has executed a "Precedent Agreement for Purchase of Canadian Gas" (Ex. Cape Cod-12) with Algonquin Gas Transmission Company for purchase of up to 2,652 MMBTU per day from the proposed New England States Pipeline Company project. However, the Company is not relying on this gas to serve its customers during the forecast period.

C. Storage Return Gas

Cape Cod has a storage contract which encompasses the storage of 700,000 MMBTU on an annual basis. This year, for the first time, Cape Cod has negotiated a transportation agreement with Algonquin for the firm delivery of 1,052 MMBTU of storage gas per day. Previous to this, all storage gas (up to 10,000 MMBTU/day) was transported by AGT on a "best-efforts" basis.

To meet forecasted normal firm requirements for 1981-85, the Company plans to obtain gas from Algonquin in the non-heating season of each year and inject it into storage for use in the following heating season. The Company states that it is confident that this gas will be available during the forecast period. Further improvements in the Algonquin pipeline should provide Cape Cod with 3,000 MMBTU/day of firm storage gas in the 1982-83 heating season and thereafter. These developments provide Cape Cod's customers with a more reliable gas supply while maintaining system flexibility.

D. Synthetic Natural Gas, Liquefied Natural Gas and Propane

Cape Cod purchases synthetic natural gas (SNG) from Algonquin SNG, Inc. Algonquin SNG operates a plant in Freetown, Massachusetts which converts naptha into SNG. Algonquin offered Cape Cod the option of reducing their take or pay obligations for SNG by approximately 50% during the 1981-82 heating season. Cape Cod accepted this option and substituted 225 MMBTU of LNG in place of 307 MMBTU of SNG previously provided by Algonquin. This substitution of LNG for higher-priced SNG will benefit the Company's consumers. Cape Cod purchases its LNG from Bay State Gas Company, which in turn purchases its LNG from Distrigas under a firm contract which runs through March 1988. The contract provides take or pay quantities as well as optional quantities. The contract was amended on July 13, 1981 to provide the additional LNG volumes used to replace the SNG not taken from Algonquin. The total volume of LNG available to the Company during the 1981-82 heating season was 876,000 MMBTU including both firm and optional quantities.

The Company has a yearly contract for the purchase of propane and expects to be able to purchase sufficient quantities of propane from its suppliers during the forecast period. For the 1981-82 heating season, the Company had contracts with Petrolane (minimum 1,266,000 gallons, maximum 1,550,000 gallons) and Suburban Gas Company (minimum 221,000 gallons, maximum 310,000 gallons), (Ex. Cape Cod-1, p. 14). The Company has propane/air storage and sendout facilities in Catumet, South Yarmouth and Chatham. The maximum daily sendout capacity from these facilities, is 9.74 MMCF/day with storage capacity of 39 MMCF. Cape Cod expects that it will send out 5-6 MMCF of propane per peak day. (Ex. Cape Cod-1, Table G-23). This propane is transported by truck.

E. Comparison of Resources and Requirements

1. Design Year

As noted, the Company's forecast of design year sendout requirements is not adequately documented. The Council is thus hesitant to make a definitive judgement on the adequacy of heating season supplies under design year conditions. There does not appear, however, to be reason for immediate concern and compliance with the conditions attached to this decision should make the Company's forecast of design year requirements more reviewable in the next filing.

2. Peak Day

The Company has a combined peak day sendout capability of 56.7 MMCF. This includes pipeline gas, SNG, propane and LNG facilities. Peak Day sendout requirements will increase with the addition of new customers to 46.3 MMCF on a design peak day in 1984-85. Thus, the Company's sendout capacity is adequate to meet the peak day sendout requirements during the forecast period.

F. Demand Management Programs

Cape Cod Gas Company is a participant in the Mass-SAVE program, which provides residential audits and follow-up arranging and financing services. Cape Cod has not developed more extensive programs to manage demand. Demand management programs, whereby utilities promote subsidized investments in energy saving equipment, have been implemented in many states. Gas utilities in California, Wisconsin, Michigan and New York are investing in conservation devices in customers' homes; the "conservation gas" those investments produce is comparable to new sup-

supplies of pipeline or supplemental supplies, and has been found elsewhere to be much less costly than such supplies. In some states, demand management programs have been found to benefit company stockholders as well as gas customers.[4] In New England, Northeast Utilities provides grants to its gas customers who install high-cost conservation measures (such as insulation and storm windows), and will install several low-cost measures itself for a nominal fee.[5] Governor King's "Program to Stabilize Utility Costs" suggested that utility companies consider implementation of a program of modest (15%) grants for high-cost conservation measures, and subsidized installation of low-cost measures.

The Council recognizes that the advisability of a grant and installation program is dependent upon the particular cost, supply, and dispatch conditions of each gas system and of the service area's customers. Therefore, the Council's opinion is that the Company should explore the appropriateness of such demand management strategies for its particular system. The strategy to be examined may include efficiency standards for new customers, and greater incentives (including financial incentives) for existing customers to save gas. Although the Company's ability to implement some such strategies may be constrained by

---

4 See Decision 92653, Application 59737, before the Public Utilities Commission of the State of California, Application of Pacific Gas and Electric Company for authority, among other things, to implement a Conservation Financing Program, January 28, 1981; Gas Utilities Residential Insulation Program, March 31, 1977; New York State Public Service Commission, Second Annual Report on Implementation of the New York State Home Insulation and Energy Conservation Act Program, January 1, 1980.

5 EFSC 81-17, Northeast Utilities, Long-Range Forecast, April 1, 1981, "Northeast Utilities Conservation Program for the 1980's and 1990's", pp. 41-46.

regulation, its ability to identify wise corporate strategies and ask the Council and the Department of Public Utilities for permission is not constrained. The Council staff will be available to assist the Company in analyzing different conservation approaches.

An additional issue relating to demand management programs is Company promotion of energy saving measures such as insulation and more efficient gas appliances. Cape Cod has provided its customers with bill stuffers and promotional pamphlets on energy conservation for several years. The Council is pleased with the thrust of this program. However, the record in this case indicates that the Company's promotional literature on energy efficient gas and electric appliances does not provide the consumer with specific energy consumption figures for these appliances. This is illustrated in Figure 1 which is taken from the Company's pamphlet entitled "Timely Savings" (Ex. Cape Cod-9). Energy consumption information is essential if consumers are to compare the costs and benefits of buying more efficient appliances. The Council expects that this type of information will be included in future promotional literature.

ENERGY SAVING GAS GLASS-LINED WATER HEATERS

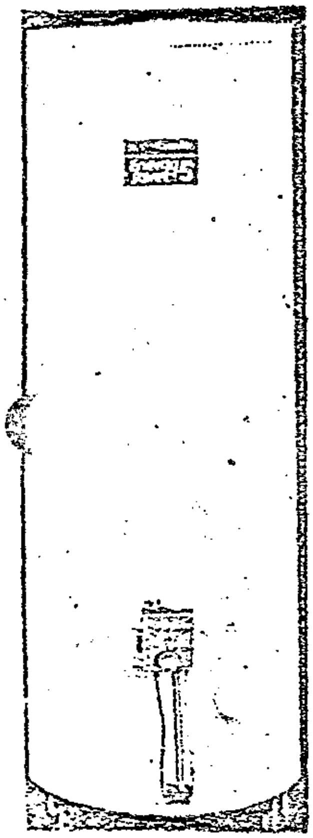
From

AOSmith

Replace Your Old Hot Water Heater Now Before it Really Costs You —

And Save Up to 35% of Your Energy

ENERGY USE?



30 GAL.
5 YEAR

ENERGY SAVER™ 5

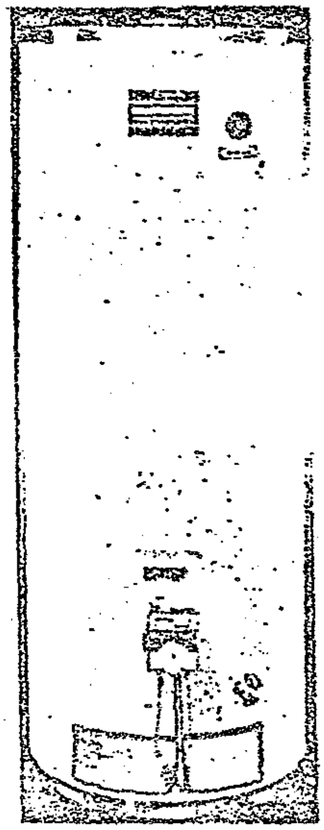
- 5-YEAR LIMITED WARRANTY
- DOUBLE DENSITY INSULATION SIGNIFICANTLY REDUCES HEAT LOSS
- HEAVY GAUGE STEEL TANK
- CORROSION-RESISTANT GLASS LINING
- ENERGY EFFICIENT FLUE BAFFLE
- FINGERTIP TEMPERATURE CONTROL AND SAFETY SHUTOFF
- ALL STEEL BURNER DESIGNED FOR NATURAL OR PROPANE GAS
- ENERGY SAVING PILOT REDUCES GAS CONSUMPTION
- BAKED ENAMEL FINISH
- AVAILABLE in 30, 40, 50, 75 AND 100 GALLON CAPACITIES
- MEETS REQUIREMENTS OF ASHRAE STANDARDS

Reg. Retail $219.95
SALE $199.95
SAVE $20.00

CONSERVATIONIST

- 10-YEAR LIMITED WARRANTY
- EXTRA THICK LAYER OF DOUBLE DENSITY INSULATION
- THERMOGARD™ DIP TUBE PROVIDES MORE HOT WATER AT OPTIMUM ENERGY SAVINGS. REDUCES LIME BUILD-UP
- HEAVY GAUGE STEEL TANK
- CORROSION-RESISTANT GLASS LINING
- BAKED ENAMEL FINISH
- ENERGY SAVER THERMOSTAT WITH FUEL- SAVING TEMPERATURE CONTROL AND SAFETY SHUTOFF
- CAST IRON BURNER DESIGNED FOR NATURAL OR PROPANE GAS
- ENERGY SAVING PILOT REDUCES GAS CONSUMPTION
- AVAILABLE IN 30, 40, 50, 65, 75 AND 100 GALLON CAPACITIES
- MEETS REQUIREMENTS OF ASHRAE STANDARDS

Reg. Retail $269.95
SALE $249.95
SAVE $20.00



40 GAL.
10 YEAR

AVAILABLE AS A
PUBLIC SERVICE FROM

**CAPE COD
GAS COMPANY**

Office and Showroom
60 NORTH ST., HYANNIS

-78-9134 394-9851 432-5790 759-2531 771-8872

VISA

INSTALLATION
AVAILABLE
AT
EXTRA CHARGE
USUALLY WITHIN
24 HOURS

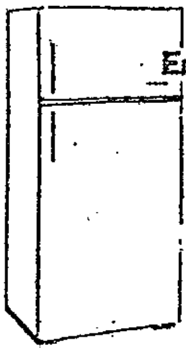
SPECIAL PURCHASE

Gibson Refrigerators

EXCLUSIVE 10 YR COMPRESSOR WARRANTY

ENERGY SAVER USES ONLY KW PER MONTH

"Designed For The 80's" to Save Even More Energy



14 Cu. Ft. FROST CLEAR . . . RT14F7WM

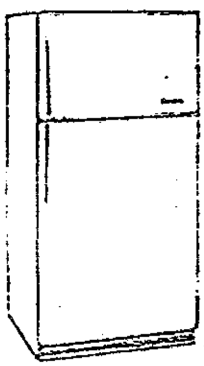
Energy Savings You Can Bank On!

- 3 ADJUSTABLE SHELVES
- SUPER FOAM INSULATION
- CONVERTIBLE - REVERSIBLE DOORS

EXCLUSIVE 10 YR. COMPRESSOR WARRANTY — ENERGY SAVER USES ONLY KW PER MONTH

ENERGY USE?

Reg. Retail $539.95
SAVE $ 60.00
SALE $479.95



17 Cu. Ft. FROST CLEAR . . . RT17F7WM

Energy Savings You Can Bank On!

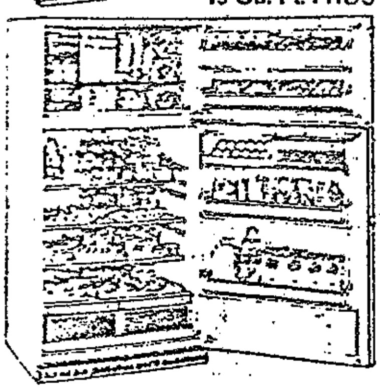
- 3 ADJUSTABLE SHELVES
- WOOD TRIM DOORS
- TEXTURED DOORS
- FREEZER SHELF

ENERGY SAVER USES ONLY KW PER MONTH

ENERGY USE?

EXCLUSIVE 10 YR COMPRESSOR WARRANTY

Reg. Retail $619.95
SAVE $ 80.00
SALE $539.95



19 Cu. Ft. FROST CLEAR . . . RT19F7WM

Energy Savings You Can Bank On . . .

- WOOD TRIM DOORS
- FREEZER SHELF
- TEXTURED DOORS

ENERGY USE?

EXCLUSIVE 10 YR. COMPRESSOR WARRANTY — ENERGY SAVER USES ONLY KW PER MONTH

Reg. Retail $639.95
SAVE $ 80.00
SALE $559.95

SPEND TO SAVE with a GIBSON CHEST FREEZER

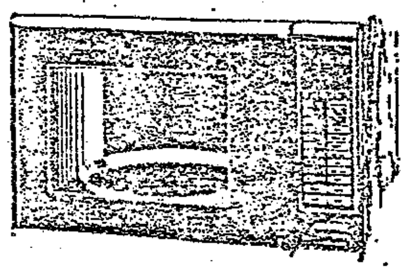
Buy Food in Quantity when Prices are Low and Save Every Day as Prices Go Up.

SAVE $70.00

Reg. Retail $369.95 SALE $299.95

SHARP Micro Wave Ovens

Featuring Our Industry Exclusive . . . .



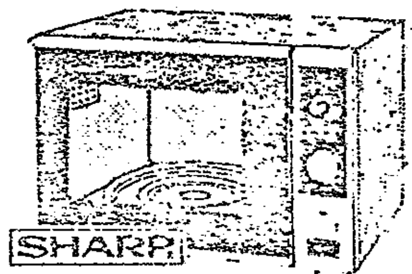
Auto-Touch Convection Microwave Oven

Features Carousel Model with Touch Control—

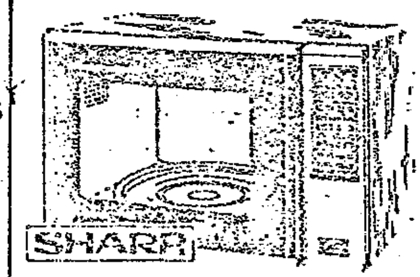
R-8320

Carousel Microwave Oven with Variable Cooking Control

Reg. Retail $399.95
SAVE $ 80.00
SALE $319.95



Model No. R-7710



Model No. R-9310

Deluxe Carousel Microwave Oven With Auto-Touch And Variable Cooking

Reg. Retail $449.95
SAVE $ 50.00
SALE $399.95

SHARP The Quality Name In Micro Wave Cooking

SEE VALUABLE COUPONS ON PAGES 5 and 10

VISA

IV. Contingency Planning

The events of January, 1981, discussed below, point out the critical reliance of Cape Cod Gas upon supplemental fuels - especially LNG. The Company relies upon LNG from Bay State Gas Company. Under the terms of the August 1, 1979 contract between Bay State and Cape Cod (Ex. Cape Cod-5), Bay State is obligated to deliver firm quantities of LNG into transport trucks furnished by Cape Cod. Transport of LNG is the sole and exclusive responsibility of Cape Cod. (Ex. Cape Cod-5, p. 11).

The Council's primary concern regarding supplementals is the adequacy of the Company's contingency plans in the event that supplies of any supplemental fuels are cut off or constrained in the future. For example, evidence in this case indicates that on January 8, 1981 Bay State Gas Company informed Cape Cod that it would be unable to supply LNG to Cape Cod at the normal rate (Tr. p. 21) and requested that Cape Cod make arrangements, if possible, to receive equivalent volumes by way of pipeline through the Algonquin system. The Company testified that Algonquin was able to make full deliveries of these volumes. (Tr. p. 22).

The Council directs the Company to address its contingency planning in more detail in its next filing. Specifically, but not exclusively, the Company should detail its plans in the event of an unforeseen cessation of any of its major supplemental supplies, coupled with a prolonged period of peak-like days. Data on Algonquin's pipeline capacity, ability to supply supplemental vapor in the event that Bay State cannot deliver, and the effect of the recent Algonquin pipeline improvements should be included in this analysis.

6) That the Company file its Second Long-Range Forecast on July 1, 1982.

7) That the Company arrange a meeting with the Council Staff to discuss the above conditions within 30 days of this decision.

Robert T. Smart Jr.

Robert T. Smart Jr., Esq.
Hearing Officer

On the Decision:
Steven Buchsbaum

This Decision was approved unanimously by the Energy Facilities Siting Council at its meeting on April 12, 1982 by those members present and voting. Voting in favor: Margaret St. Clair, Richard A. Croteau, George Wislocki, Eileen Schell (by designee), John Bewick (by designee), George Kariotis (by designee), Thomas J. Crowley, Dennis J. Brennan.
Abstaining: Harit Majmudar.

5/5/82

Date

M. N. St. Clair

Margaret N. St. Clair
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of Lowell Gas Company's Fourth Annual Supplement to Its Long Range Forecast, 1980-1985	)	EFSC 80-16

FINAL DECISION

Robert T. Smart Jr., Esq.
Hearing Officer
March 15, 1982

On the Decision:
Steven Buchsbaum

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of Lowell Gas Company's Fourth Annual Supplement to Its Long-Range Forecast, 1980-1985	)	EFSC No. 80-16

FINAL DECISION

This Decision APPROVES the Fourth Annual Supplement of the Lowell Gas Company, subject to the CONDITIONS attached to this decision and order. The Council notes that the Company failed to fulfill several conditions contained in the Council's Third Supplement, EFSC 79-16. Those conditions are repeated in this decision with the expectation that they will be fulfilled in the Company's next Long Range Forecast. These conditions require more complete documentation of the Company's methodology and incorporation of explicit projections of sendout to various classes of customers.

Suggestions regarding improved forecasting techniques are provided to help the Company increase the usefulness of its forecast to the Council and to the Company itself.

The first section contains an introduction and a procedural history. The second section describes and reviews the Company's sendout forecast and sources of supply. The third section discusses Lowell's contingency planning. The fourth section contains the Order and Conditions to next year's filing.

I. INTRODUCTION

Lowell Gas Company supplies gas to Lowell, Billerica, Chelmsford, Dracut, Dunstable, North Reading, Pepperell, Tewksbury, Westford, Wilmington, and Tyngsborough. It is the fourth largest gas company in Massachusetts. Total annual gas sales are broken down almost evenly between the residential and the commercial/industrial sectors. Lowell sells roughly twice as much gas in the heating season as in the non-heating season, and that ratio is forecasted to increase. The Company hopes to double its gas sales by the year 2000, and projects an average annual growth rate of 3.7%.

In its review of forecasts and supplements, the Council requires[1] each gas company to project "the gas requirements of its market area" over a five year period and to describe "actions planned to be taken by the Company which will affect capacity to meet such needs or requirements...", G.L. c. 164 section 69I. Under EFSC Rule 62.9(2), forecasts of sendout must be based upon historically accurate information and reasonable statistical projection methods. In its decisions in recent years, the Council has found statistical projection methods to be "reasonable" if they are reviewable, appropriate and reliable. A methodology is reviewable if it is clearly and thoroughly described, or documented, so that its results can be duplicated by another person given the same information. A methodology is appropriate

---

1 For a more extensive discussion of the scope and standards of review applied by the Council, See Boston Gas Company, EFSC 81-25.

when it is technically suitable for the size and nature of the particular system. It is reliable when it provides a measure of confidence that the assumptions, judgements and data which comprise it will forecast what is most likely to occur. A gas company must demonstrate that it will have sufficient supply available to meet firm needs on an annual basis, during the heating season, and on peak days. It must also show that it is pursuing a "least cost" supply strategy.

The Lowell Gas Company filed its Fourth Annual Supplement to its 1976 Long-Range forecast on November 7, 1980. This Supplement projects sendout and describes the Company's supply plan for the split years 1980-81 through 1984-85. Several new facilities were proposed for adjudication[2] in the filing, but were withdrawn by a letter dated March 30, 1981 from the Company's attorney, Scott P. Lewis, Esq.

The Company gave proper notice of these adjudicatory proceedings by publication in local newspapers and posting at the city and town halls in its service territory. The Attorney General filed a Petition to Intervene on March 10th. A pre-hearing conference, attended by representatives for Lowell Gas Company and the Attorney General, was held on March 23, 1981. Lowell filed a written Opposition to the Attorney General's Petition on March 30th. After receipt of additional

---

2 In Table G-17, Lowell proposed the construction of LNG storage and vaporization facilities in Lowell and Pepperell. In Table G-21 it proposed to increase the diameter from 6 inches to 18 inches of a 1.3 mile length of a gas transmission pipeline running from Billerica to Chelmsford. The Company stated at the hearing that these facilities were no longer needed, due to the construction in Dracut of a new Tennessee Gas Pipeline Company take station, which would allow Lowell to distribute its pipeline supplies more efficiently.

written materials from the parties, the Hearing Officer allowed the Attorney General to intervene on April 28, 1981. Discovery was completed in October of 1981. A Procedural Order on October 27, 1981 requested a list of witnesses and document responses from the Company, and a "statement of issues" from the Attorney General. It set a November 23, 1981 hearing date. The Attorney General filed a "Statement of Issues" on November 13, 1981. After requesting a postphonement of the hearing, Lowell filed a "Motion to Strike Attorney General's Statement of Issues", which Motion was withdrawn after the parties reached agreement at a December 4, 1981 pre-hearing conference.

The hearing was held on December 7, 1981. No representative from the Attorney General's Office attended. Lowell offered into evidence its Fourth Supplement, EFSC Staff Information Requests and Company responses, the pre-filed testimony of its President, F.L. Putnam Jr., extensive materials from the Massachusetts Department of Public Utilities investigation of last winter's "gas crisis" (D.P.U. Docket No. 555), and other documents pertaining to the Company's emergency procedures, conservation programs, and gas supply agreements. The Company provided two witnesses, Charles O. Swanson, Vice President and General Manager of the Lowell Gas Company, and Albert C. Dudley, Vice President of Gas Supply at the Colonial Gas Company ,[3] who answered questions from the EFSC Staff.

3 Until July 30, 1981 Colonial Gas Energy System was a holding company which owned Lowell Gas Company and Cape Cod Gas Company and also owned Transgas Inc. which transports propane and LNG and other cryogenic gases. On that date Lowell Gas Company succeeded to the assets, liabilities and business of Colonial Gas Energy System pursuant to a reorganization in which Lowell Gas Company's name was changed to Colonial Gas Company. Colonial Gas Company now operates a Lowell Gas Company division and a Cape Cod Gas Company division and owns Transgas, Inc.

IV. Forecast Methodology

A. Background

The Company's forecasts of sendout and supply have been reviewed annually by the Council since 1976. The methodology used in these forecasts has improved over the years and the Company has attempted to respond to the conditions contained in the Council's previous decision. However, the Company has not gone far enough in one important area: the documentation of its methodology for forecasting sendout. The lack of documentation and the use of inappropriate forecasting techniques forms the basis for the Council's criticism of the Company's forecast of sendout in this decision.

A review of the conditions contained in the Council's previous decision, on the Company's Third Supplement, shows that the Council has previously asked the Company for documentation of its sendout forecast. The relevant conditions contained in EFSC 79-16 are:

1) That potential additional conservation from existing residential customers be considered in the future Forecasts and Supplements.

2) That conservation projections for both new and existing residential customers be documented in future Forecasts and Supplements.

3) That the Company explain any judgements made concerning conservation, the basis for said judgements and the manner by which such judgements are incorporated into the forecast in the next filing.

4) That all projected annual use per customer factors used to prepare the forecast for normal sendout be documented in the next Forecast or Supplement.

5) That the manner by which the Heating Use Per Average Customer (Table G-1) for the forecast years were derived be explained in the next Forecast or Supplement.

The Company has made some effort to include conservation and other factors affecting use per customer in its current forecast. The Company does project declining use per customer in the largest residential class -- those customers with central heat. The Company speculates in its Forecast:

> "It is quite probable that the decrease in average annual use per customer is based on a variety of conditions; such as, lower thermostats, alternate source of energy (wood), more efficient equipment or the addition of insulation and weatherproofing material."

However, conditions two through five from EFSC 79-16 specifically ask for documentation of the methodology used to estimate future use per customer. All documentation, estimates and judgements used in projecting these factors should have been included in the Forecast. They were not. The following sections of this decision explain the Company's sendout forecast in more detail and illustrate how the lack of documentation has made it difficult to review the forecast. The appropriateness of the Company's forecasting techniques is also discussed.

B. Forecast of Sendout

The Company's forecast of sendout includes forecasts of sendout by customer classification and a forecast of peak day sendout. Overall, the Company projects an average annual growth rate of 3.7% in total sales over the five year forecast period.

The Company stated it is not supply constrained during the forecast period (Tr. p.31). This is important in the context of a forecast of future sendout requirements and represents a departure from past years when supply limitations were widely viewed as the major constraint on sales. Given the lack of supply constraints in the short term, the future sendout of the Company will depend on market conditions and changes in consumption patterns to a large extent. In light of the turbulent period which may accompany gas price decontrol, the importance of accurately forecasting future sendout requirements has increased for the Lowell Gas Company and the entire Massachusetts gas industry.

Sendout for each customer class is first projected and then these forecasts are aggregated to achieve a system-wide forecast. The forecasts of sendout by customer class include forecasts of sendout to residential central heating customers, residential space heating customers, residential non-heating customers, commercial/industrial customers and interruptible customers. A breakdown of sendout to these customers, for the 1981-82 and 1985-85 split years, is presented in Table 1.

TABLE 1

Lowell Gas Company

Sendout by Customer Class
(MMCF)

	1981-82		1984-85	
	Heating Season	Non-Heating Season	Heating Season	Non-Heating Season
RESIDENTIAL				
Central Heat	3253.1(41%)	1636.9(35%)	3469.3(41%)	1752.0(40%)
Space Heat	503.7(6)	248.4(5)	462.6(5)	277.7(6)
Non-Heat	63.3(1)	70.1(2)	50.4(1)	53.0(1)
COMMERCIAL/ IND. (firm)	3485.9(44)	1749.0(38)	4104.7(48)	2074.8(48)
INTERRUPTIBLES	132.1(2)	738.4(16)	16.3(0)	18.9(0)
COMPANY USE/ UNACC.	561.2		603.3	
TOTALS	8140.0	4302.1	8866.2	4016.8

NOTE: Numbers in parentheses denote percentage of total seasonal sendout.

The forecasts of sendout in the residential classes are all done in a similar manner. The methodology can be simply stated in the following equation:

Sendout = (No. of customers) X (Average use/customer) X (weather factor)

Sendout in a particular year is a function of the number of customers in the system in that year, the average gas consumption of these customers, and the weather. To achieve a forecast of sendout in the future each of these variables must be projected separately.[4]

The forecast of sendout in the Commercial/Industrial classes does not explicitly account for changes in use per customer. Rather, the number of new customers is estimated and the estimate of usage by these new customers is added to projected usage by existing commercial and industrial customers.

---

4 The interplay among these variables is exhibited by the following example: In 1970 the Company had 19,422 central heating customers with an average use 188.7 MCF per year. Total sales to these customers in that year were 3,665,462 MCF. In 1980 there were 29,652 central heating customers, an increase of 53%. However, average use per customer in 1980 was only 148.8 MCF -- down 21% from 1970 levels. Therefore, sendout to the class increased by only 20% to 4,413,388 MCF. It must be noted that 1970 was 8% colder than 1980 and this partially accounts for the lower average use and lower than expected growth. On a weather-normalized basis, however, usage declined in every year except two during the decade to a point where average usage per customer in 1980 was 16% lower than in 1970.

In conformance with standard industry practice, the Company constructs two sets of forecasts: one under normal weather conditions and one under design conditions. Lowell uses the average number of degree days/year in the last 20 years to define normal weather. Design conditions are defined by the Company as the number of degree days during the coldest split year of the past twenty. This procedure, as practiced by Lowell, is judged adequate by the Council.

The following sections of this decision describe and analyze the forecast of sendout in the residential classes and the commercial/industrial class, and the forecasts of system-wide requirements for peak day and design heating season conditions.

1. <u>Forecasts of Use per Customer in the Residential Classes</u>

As shown in the sendout equation on page 11, gas use per customer is one of the three key elements in the Company's forecast methodology for the residential classes. To forecast use per customer in the residential central heating class (which accounts for approximately 85% of residential sendout and 40% of total sales) the Company relied on an "eyeball" estimate based on the trend in customer usage during the last fourteen years. This estimate was then adjusted by the Company to reflect its opinion that customer conservation will reach its full potential by 1984, and that further declines in customer usage after that date are unlikely. This important judgement or assumption was not contained in the Forecast Supplement and is one example of the type of information which the Company must include in its next filing. Furthermore, if the Company judges that the future trend will merely be a continuation of past trends, statistical techniques are available to ensure that the projection accurately reflects the past trend.

No statistical tools were used to estimate the level of residential usage per customer over the forecast period. The Company provided fourteen years of historical sendout data used in its eyeball estimate in response to a Staff information request. It did not explain how this data was used to forecast use per customer. The historical and projected use per customer figures are presented in Table 2. Figure 1 presents the historical data and projections in the residential central heating class. The Company forecasts that use per customer in 1985 will decline only slightly (2.7%) from the 1980 sendout levels. This represents a significant slowdown in the trend established in the last 10 years. The Council Staff attempted to replicate this trend using the

Company's historical data. Trend lines using the total set of historical data (1967-80) and using post oil embargo data (1973-80) were derived by linear regression analysis. Both of the equations and trend lines are presented in Figure 1 for illustration purposes. As shown in the figure, the Company's forecast of use per customer is quite close to the Staff's linear regression line based on the fourteen years of data. A regression of this type extends the historical trend by calculating a line which most closely "fits" the historical data. Despite the fact that the Company's projection is quite close to one of the regression lines, the use of data from the late 1960's is inappropriate as used by the Company. This is particularly true because the Company has made no attempt is made to explicitly relate changes in customer use to the important factors driving these changes (such as the price of gas, customer awareness of energy conservation and the price and availability of fuels used in conjunction with gas such as wood and coal).

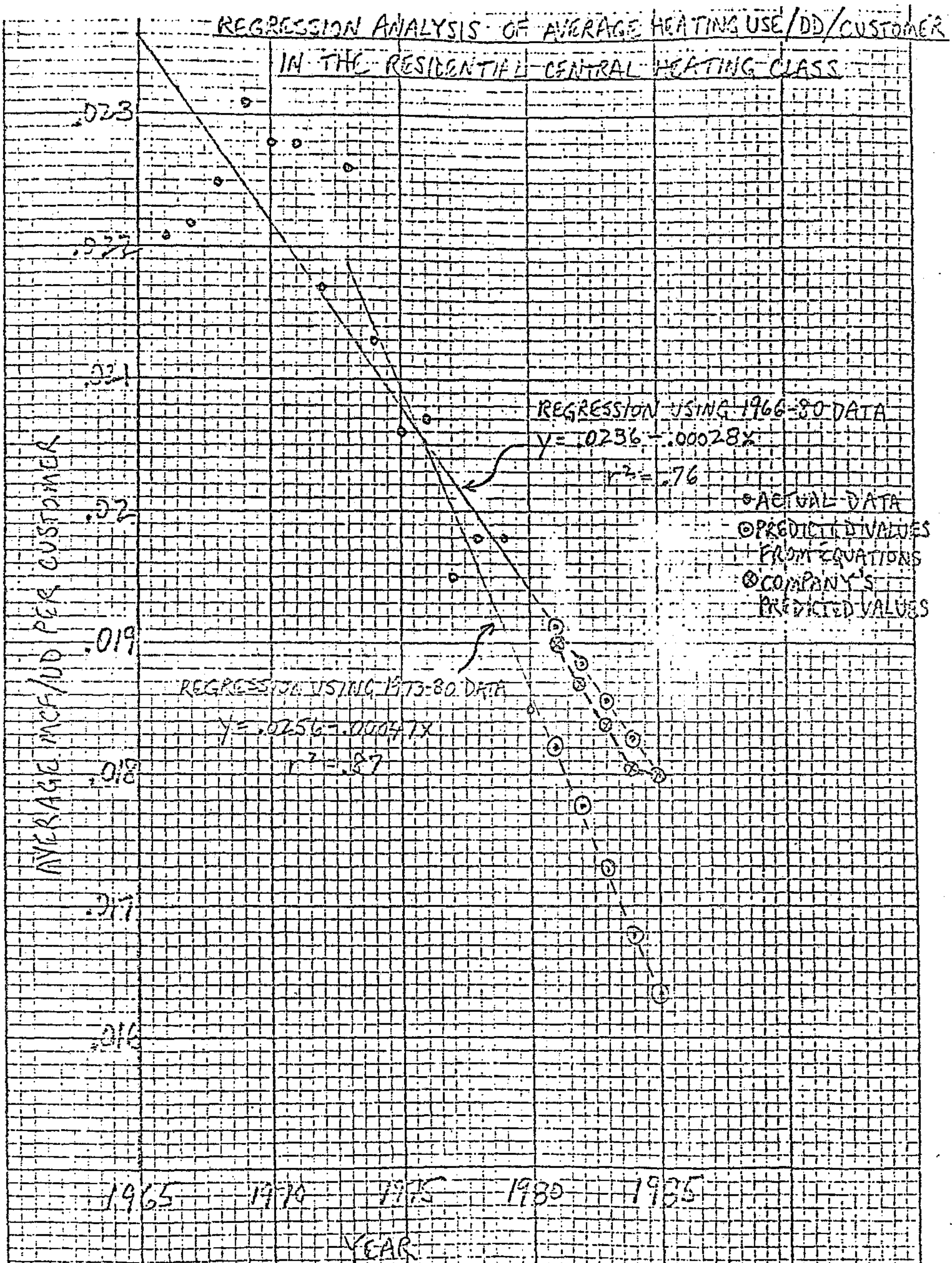
Table 2

Lowell Gas Company

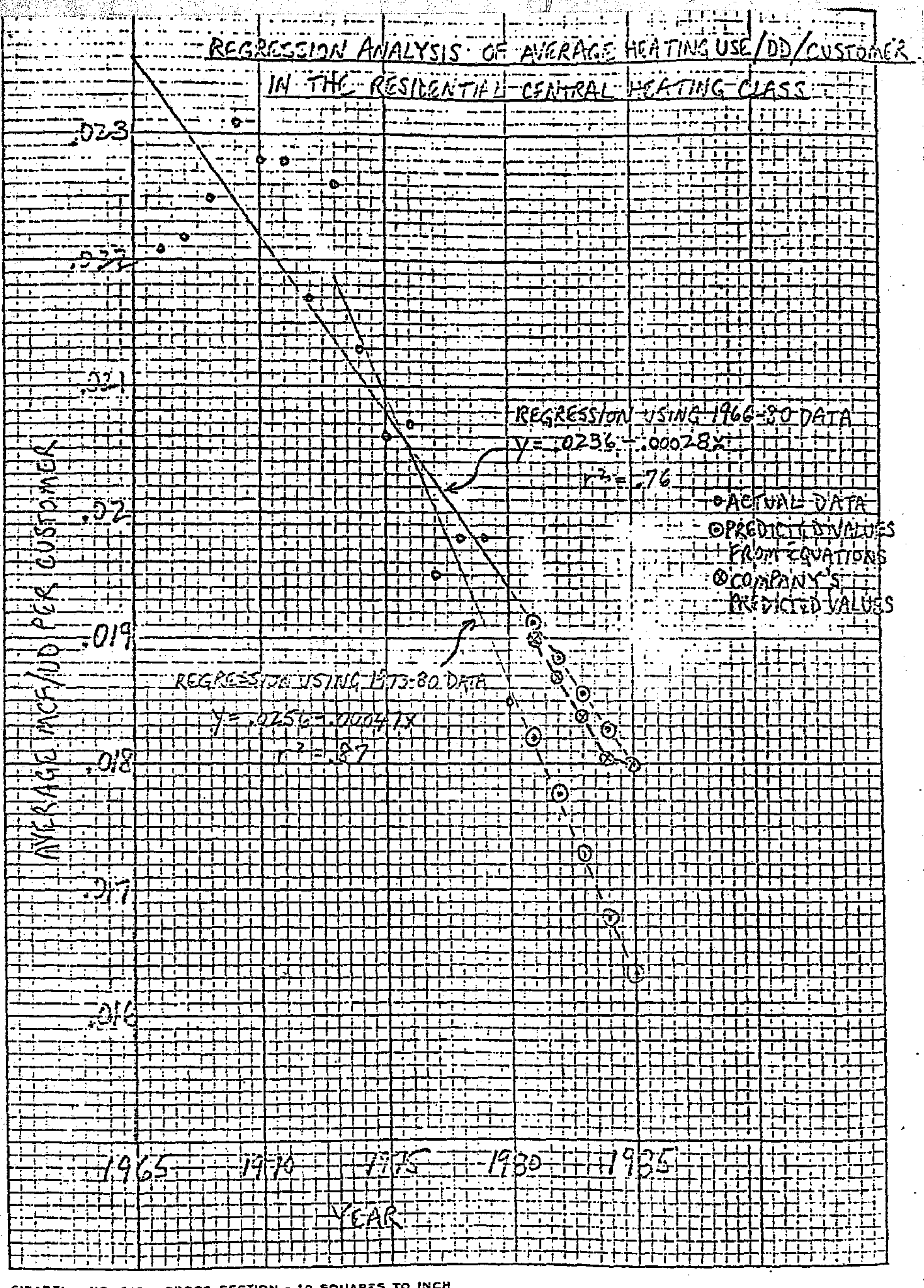
AVERAGE ANNUAL USE PER RESIDENTIAL CUSTOMER
(MCF)

Year	Central Heating Customers Base Load	Central Heating Customers Heating Load	Space Heating Customers	Non-Heating Customers
1966	49.6	135.7		
67	49.2	135.3		
68	49.1	138.2		
69	45.1	141.8		
70	45.5	140.0		
71	43.8	140.0		
72	47.0	133.2		
73	44.5	138.8		
74	45.6	130.8		
75	44.6	126.5		
76	47.6	127.1		
77	48.5	119.7	102.8	
78	44.0	121.6	103.8	23.6
79	40.6	121.6	98.5	27.4
80	40.9	113.6	102.2	22.9
Forecast				
1981	40.56	121.0	104.4	22.26
82	40.57	114.8	104.4	24.38
83	39.96	112.9	104.4	24.92
84	38.88	110.8	104.4	24.98
85	37.86	110.5	104.4	24.31

All data is weather normalized to 6140 Degree days, the average in the Lowell area.



CITADEL NO 642 - CROSS SECTION - 10 SQUARES TO INCH



CITADEL NO 642 - CROSS SECTION - 10 SQUARES TO INCH

Using the Company's technique, historical changes in use/customer are merely "eyeballed" to form a trend into the future. This technique is best applied to cases where significant explanatory variables remain unchanged. The Company's use of data from the late 1960's violates this condition. Gas prices in Massachusetts declined steadily during the 1950's and 1960's. By 1968 the average residential price of gas in Massachusetts had fallen to approximately $1.50/MCF from over $2.00/MCF in the 1950's (prices in nominal dollars). Given this price trend and the lack of public awareness concerning energy supply, it is not surprising that average heating use per residential customer rose during this period. This is exhibited by the data from the 1960's included in Figure 1; use per customer per degree day rose from 1966-1971. With the oil embargo of 1973, public awareness of energy supply constraints was heightened and oil and gas prices in the region began to escalate. By 1980 the average residential price of gas in the Commonwealth was $5.41. Average use per residential central heating customers in the Lowell service area dropped 18% between 1970 and 1980.

The coincidence of price increases, accelerated public awareness and declining usage in the post-1973 era point to the significance of gas prices in the customer use equation. Without any means to account for price, the Company's use of 1966-72 data is inappropriate. This data should not be used in a simple eyeball estimate of future consumption. The effect of eliminating this data from the regression analysis is shown in Figure 1. The regression line based on 1973-80 data yields a much lower projection of future use per customer. There is risk associated with an overestimate of average usage: The Company might thereby over-commit to supplementals, with take-or-pay obligations, causing the average price of gas to rise. This equation, however, is also of limited usefulness because explanatory variables, such as price and public awareness, are not included in the equation. The Council encourages the Company to use its historical customer use data in conjunction with historical price data to formulate a multi-variate regression model to project future use per customer. The Council staff is ready to assist the Company in this endeavor.

Another problem with the Company's technique is that the data series used by the Company does not make any distinction between customers on line at the beginning of the historical period and those new customers added during the period. To the extent that new customers tend to use more gas than the average existing customer the trend line established by the Company is sensitive to the the numbers of new homes added to the system each year. The Company is therefore directed to provide documentation of the effect of new customers on use per customer in the future and show how this is accounted for in the forecast methodology.

2. Forecast of New Residential Customers

The Company's forecast of the number of new customers is another important variable in determining future gas requirements. The Company will be able to control this variable directly through its policies on marketing and new hook-ups. The Company has stated that hook-ups of new gas customers in 1981 has been lower than in 1980, but that the 1980 demand for hook-ups had been higher than expected. The Company states its forecast of new customers is based on its "Sales Department's best estimate as to how the anticipated growth in the area will be reflected in gas sales." (Ex. Lowell-1, Forecast Supplement,p. 6). The Council recognizes the inherent difficulty of forecasting customer additions and also recognizes that new customer hook-ups can be limited by the Company if adequate supplies will not be available. At the same time, the Council wishes to point out that as decontrol of the well-head prices of most gas supplies is phased in, the Lowell Gas Company will need better data on the market potential for gas in new construction and gas conversions in residential markets. The Council urges the Company to perform market research studies so that the Company can better assess the future of the home heating market and the commercial/industrial market under various price assumptions for oil, gas, and electricity.

3. Commercial/Industrial Forecast

The commercial/industrial forecast includes the number of commercial and industrial customers in each year and the projected aggregate sendout to these customers. Aggregate annual sendout is broken down into sendout during the heating season and sendout during the remainder of the year, as per EFSC regulations.

No forecast of average use per commercial/industrial customer is provided in the Company's Forecast. The Company merely estimates the number of new customers and adds their use incrementally to the existing commercial/industrial use. The Company states that, "The forecast of Commercial and Industrial sales cannot be based on an average use per customer. One customer may use 100 Mcf/year and another 50,000 Mcf/year." (Ex. Lowell-1, Forecast Supplement, p.8).

While it is true that there will normally be a large variation in the sendout within any utility company's set of commercial and industrial customers, it is possible to use data on use per customer to derive a more accurate forecast of sendout to these customers. Conservation efforts in the commercial and industrial sectors for example, work to reduce the average use of existing customers. If the Company includes this effect in its forecast methodology there is no documentation of it in the Forecast Supplement. The Company forecasts a 5.7% compound growth rate in annual Commercial/Industrial sales during the forecast period. Total sales to this class of customers is projected to increase 945 MMCF from 1981-82 to 1984-85 (see Table 1). The Company's forecast does not explain where this 945 MMCF will come from. It may assume that it will lose none of its existing customers, and that their usage will remain the same. In this case, the 945 MMCF would come entirely from new customer loads. If, on the other hand, it expects to lose some of its existing customers and that usage per customer will decline (as it has in the residential class), then the Company is predicting addition of new commercial and industrial load well in excess of 945 MMCF. An explicit forecast of existing customers losses and use per customer by these customers would provide a far better base from which to make realistic projections of new commercial and industrial load. The Company is therefore directed to assemble historical data on use per customer for a constant sample of long-standing commercial/industrial customers, and to attach this data to its next filing. It should also use this data in order to accurately forecast trends in use per customer in this class. The Company's documentation should explain any statistical methods and judgements used in forecasting future use/customer figures in both existing and new segments of the commercial and industrial class.

4. Forecast of Peak Day Requirements

The Company has revised its peak day design criteria from 65 degree days (DD) to 67 DD to reflect the actual temperatures recorded on December 25, 1980. This was the coldest day in the last 25 years in the Lowell service territory. In developing its forecast of peak day requirements, the Company works with a use/customer/DD figure which is approximately 20% higher than the figure used to forecast design year requirements. The Company states that it has done so because the peak day is likely to occur in January or February when MCF/DD is about 20% higher than the heating season average under design conditions. In order to determine MCF/DD in January and February, the company has plotted sendout vs. degree days for each day in these months, determined the slope of this relationship and estimated peak day sendout using the peak day degree days. Actual sendout figures from December 25, 1980 and January 4, 1981, support the reasonableness of the Company's peak day forecast technique. On Christmas Day, December 25, 1980, the average temperature in Lowell was $-2^{\circ}F$, which is 67DD. Sendout on this day was 91,000 MMCF. On Sunday, January 4, 1981 the average temperature was 1°F or 64DD, and sendout was also 91,000 MMCF. In its Forecast, the Company predicted sendout of 93,900 MMCF on a day when temperatures averaged $0^{\circ}F$ (65DD). Using the Company's methodology, sendout on a day with 67DD should be approximately 96,400 MMCF. The Company stated that had either of the two coldest days last year had been working days, it is likely that sendout would have approached this figure. Thus, the Company's peak day forecast appears reasonable.

5. Forecast of Sendout During a Design Heating Season

The forecast of sendout requirements under design conditions is used to demonstrate that a Company is capable of maintaining firm service during colder than normal heating seasons. Lowell states it has adequate supplies to meet sendout requirements during a design year. The Company defines its design year as the coldest year in the past 20 years.

The Company's design heating season is effectively 9.8% colder than a normal (20 year average) heating season. However, the Company's estimate of total heating season sendout under design conditions is only 4.2% higher than normal.

Several factors are relevant to an accurate forecast of design year sendout requirements, including:

1) the temperature sensitivity of the system load

2) sendout/DD as a function of DD

The first factor is important because an accurate forecast of sendout during a design heating season must account for the effects of colder temperatures on the different components of the connected load. Space heating use will be greatly affected by temperature while water heating and cooking use will be only slightly affected. This means that holding other factors constant, total sendout will not increase proportionately with an increase in the number of degree days.

The second factor is important because heating use/DD tends to rise as the temperature outside gets colder. This is evident from the empirical data used by the Company to forecast peak day requirements and discussed in the previous section. Holding other factors constant this data indicates that the percentage difference between sendout requirements under design conditions and sendout requirements under normal conditions should be larger than the percentage difference between degree days in a design year and degree days in a normal year. This follows from the empirical evidence on MCF/DD provided by the Company and the fact that a design year will include a larger number of colder than average days than a normal year.

The Company's forecast has not explicitly accounted for either of the two above-described factors. To justify its forecast of design heating season use, it should do so. Accordingly, the Company is directed to provide adequate documentation of its methodology for estimating design year sendout requirements in its next Forecast, including:

1) explicit and separate treatment of base load and temperature sensitive load
2) a derivation of the MCF/DD factors used in estimating design year sendout requirements including on explanation of why the factor presently used does not reflect the higher MCF/DD which can be expected during very cold weather.
3) an explanation of any judgement factors used in this analysis

The Company should have provided this documentation in its Fourth Supplement; condition No. 6 to the Council decision on the Third Supplement, EFSC 79-16, stated:

"That all estimated total Company base loads and heating components per degree day used to calculate design year and peak day sendout for each of the 5 forecast years be stated and the basis for them given in the next filing".

B. Forecast of Supplies

1. Background

Like all other gas companies in the Commonwealth, Lowell relies on a diverse mix of supplies to provide gas to its customers. During the non-heating season, when demand is low, essentially all of the gas provided by the Company is natural gas transported from Texas and Louisiana via the Tennessee Gas Transmission Company's pipeline. During the heating season, the Company supplements these pipeline supplies with gas stored underground in New York and Pennsylvania, LNG, propane and purchases from other Companies. Roughly 60% of Lowell's heating season supply is pipeline gas and 23% is gas stored underground. The remainder is LNG(14%), propane(2%) and purchases from the Boston Gas Company (1%). These figures are shown in Table 3 along with normal firm sendout of each of these supplies.

The following sections of this Decision discuss each of these supply sources in detail.

Table 3

Lowell Gas Company

HEATING SEASON SUPPLIES AND SENDOUT

(MMCF)

PIPELINE	1980-81 Total Supply Available	1981-82 Total Supply Available	1981-82 Normal Firm Sendout
Contract Demand	5262 (60%)	5252 (60%)	5019
Storage-Firm	-	1726 (20)	
Best-Efforts	2048 (23)	274 (3)	1722
NON-PIPELINE			
Propane	157 (2)	188 (2)	168
LNG Storage	1277 (14)	1179 (14)	1102
Inter-System Purchases	100 (1)	100 (1)	100
TOTAL SUPPLY	8844 (100%)	8719 (100%)	8111 (100%)

2. Pipeline Supplies

Lowell's forecast of supplies is based on the assumption that its firm contracts for pipeline supplies will be fulfilled by the Tennessee Gas Transmission Company. This contract runs until November, 1988.

3. Storage Return Gas

The cold weather of December 1980 and January 1981, and consequent supply emergency, point out the importance of storage return gas to the Lowell Gas Company. Adequate winter supplies of gas to firm heating customers was to some extent predicated on the arrival of gas stored in underground porous rock formations in Pennsylvania and New York. Yet the transportation of this gas was available only on a "best efforts" basis -- which meant that it would be delivered only when there was sufficient capacity in the Tennessee pipeline. Commencing on December 15, 1980, deliveries of the stored gas to Lowell were greatly reduced by the Tennessee Gas Pipeline Company. The circumstances surrounding this reduced service are the subject of DPU 555 proceedings. When the Council staff inquired about the cause of this lack of delivery in an information request in this proceeding, Lowell responded, "we did not know then and we do not know now the nature of the "operational problems" on Tennessee's system". (Ex. Lowell-2, p.5) Fortunately, after FERC approval of substantial improvements in Tennessee's pipeline, Lowell has been able to secure firm transportation for the bulk of its underground storage gas.

Lowell Gas Company and Tennessee Gas Pipeline Company have signed a new storage-return gas agreement, which provides for firm transportation of up to 15.691 MMCF/day of gas stored in Pennsylvania and New York State. Previously, this gas had been available only on a "best efforts" basis. This effectively increases the Company's firm pipeline supplies on peak days by approximately 38% -- a sizeable increase. Firm transportation of this gas provides Lowell's customers with increased reliability of supplies and places the Company in a much more secure position with regard to peak day and heating season sendout. The Company stated that this increased supply would, in part, reduce its reliance on supplemental fuels, tending to reduce the average cost of gas. The Council encourages Company efforts in this direction and requests that the Company explain in its next filing estimate the impact on customer rates of the displacement of supplemental gas by the new storage return gas.

4. Supplemental Fuels

The Council has previously encouraged the Company to seek long-term commitments for supplemental supplies. (EFSC 80-5, p.12). The Company has made a major step in this direction by contracting for firm transportation of the underground storage gas as discussed in the previous section.

The Company continues to rely on year to year purchases of LNG and propane, which constitute approximately 15% of heating season supplies. The Company has not shown that this policy, rather than securing long-term contracts is in the best interests of its customers, although the Company stated, "... by purchasing on a spot basis, we're able to take advantage of lower prices in almost every case. We buy the majority of our LNG and propane during the summertime, when we are able to get much lower prices. Because of the availability, we've had no difficulties in buying (supplemental fuels)." (Tr. pp.20,21) Taken alone, the Company's statement concerning purchase costs for LNG means that Lowell's customers will benefit from the continuation of this purchasing strategy. Of course, Lowell has no guarantee that its suppliers of LNG and propane will continue to renew the yearly supply contracts sought by Lowell. However, given the nature of the supplemental gas market and Lowell's relatively small LNG requirements, this does not appear to be a problem. The Council intends to examine the trade-offs between cost and reliability of supplementals, and will seek the involvement and cooperation of the Lowell Gas Company.

5. Peak Day Supply

One peak days, when sendout is highest, the mix of supplies used to meet system requirements departs radically from the average mix over the entire heating season. This is due primarily to the fact that pipeline supplies are constrained by the capacity of the pipeline and the contractual agreements between Lowell and the Tennessee Gas Transmission Company.

As discussed in the preceding sections, supplemental fuels play a key role in meeting peak day requirements. Prior to the 1981-82 heating season, firm pipeline supplies covered only 34% of peak day requirements. Now with the addition of the firm storage return gas, the Company can meet 47% of its requirements with the combination of pipeline supplies and firm storage return gas. The Company's substantial capacity for LNG and propane sendout remains unchanged and the Company's total sendout capability is approximately 43% above the peak day requirement foreasted for the 1981-82 heating season. This substantial reserve capacity means that the Company should have sufficient resources to provide a "necessary energy supply" during the forecast period as required under G.L. c. 164 sec. 69H et seq.

6. Demand Management Programs

Lowell Gas Company Company is a participant in the Mass-Save program. Demand management programs, whereby utilities promote and subsidize investment in energy saving equipment, have been implemented in many states. Gas utilities in California, Wisconsin, Michigan and New York are investing in conservation devices in customers' homes; the "conservation gas" those investments produce is comparable to new supplies of pipeline or supplemental supplies, and has been found elsewhere to be much less costly than such supplies. Demand management programs have been found to benefit company stockholders as well as gas customers.[5] In New England, Northeast Utilities provides grants to its gas customers who install high-cost conservation measures (such as insulation and storm windows), and will install several low-cost measures itself for a nominal fee.[6] Governor King's Program to stabilize Utility Costs suggested that utility companies consider implementation of a program of modest (15%) grants for high-cost conservation measures, and subsidized installation of low-cost measures. At the present time, Lowell's participation in Mass-Save is limited to providing audits.

---

5 See Decision 92653, Application 59737, before the Public Utilities Commision of the State of California, Application of Pacific Gas and Electric Company for authority, among other things, to implement a Conservation Financing Program, January 28, 1981; Public Service Commission of Wisconsin, Decision 05-GV-2, Class A Gas Utilities Residential Insulation Program, March 31, 1977; New York State Public Service Commission, Second Annual Report on Implementation of the New York State Home Insulation and Energy Conservation Act Program, January 1, 1980.

6 EFSC 81-17, Northeast Utilities, Long-Range Forecast, April 1, 1981, "Northeast Utilities Conservation Program for the 1980's and 1990's", pp. 41-46.

The Council recognizes that the advisability of a grant and installation program is dependent upon the particular cost, supply, and dispatch conditions of each gas system and of the service area's customers. Therefore, the Council's opinion is that the Company should explore the appropriateness of such demand management strategies for its particular system. The strategy to be examined may include efficiency standards for new customers, and greater incentives (including financial incentives) for existing customers to save gas. Although the Company's ability to implement some such strategies may be constrained by regulation, its ability to identify wise corporate strategies and ask the Council, the Department of Public Utilities, and the General Court for permission is not constrained. The Council staff will be available to assist the Company in analyzing different conservation approaches.

III. Contingency Planning

The situation of the Lowell Gas Company during January 1981 was examined briefly in the section on storage return gas. According to the Company, the simultaneous occurrence of three separate events (abnormally cold weather, reduced supplies of gas stored in Pennsylvania and New York and an interruption in LNG supplies) created a difficult contingency for the Company. These adverse circumstances obligated the Company to enter the spot market on short notice. Through the efforts of Company officials, supplies of gas were purchased and transported from as far away as Alabama. The Council compliments the extraordinary efforts made by Company officials during this time period. At the same time, the Council feels that the need for extraordinary efforts during the emergency indicates that spot purchases of supplemental gas during the heating season can be both difficult to obtain and expensive. This is important for companies such as Lowell, which are dependent on supplemental fuels during the heating season. The Company's contingency planning, as described in the Company's forecast, does not seem adequate in light of the Company's heavy reliance on LNG and the difficulties experienced last year. The Company should describe its contingency plans for the cessation or interruption of supplemental gas by any of its major suppliers. The Council directs that more explicit documentation of the Company's contingency plans be included in the Company's next Forecast.

The Council appreciated the opportunity to examine the emergency curtailment procedures provided by the Company in the course of this review.

VII Order and Conditions

The Fourth Annual Supplement to the Lowell Gas Company's 1976 Long Range Forecast is hereby APPROVED. The Council orders the Company to fulfill the following conditions in its next Long Range Forecast:

1. That conservation projections for new and existing residential customers be documented, separately, in the Company's next Forecast.
2. That the Company explain any judgements made concerning conservation, the basis for said judgements and the manner by which such judgements are incorporated into the forecast in the next filing.
3. That all projected annual use per customer factors used to prepare the forecast for normal sendout be further quantified and documented in the next Forecast.

4. That the Company explain how it derived the figures in Table G-1 for Split-Year Heating Use per Customer per Degree day, and Split-Year Base Use per customer, for the forecast years.

5. That the Company document its methodology for estimating design year sendout requirements for the five years in its next Forecast, including: (a) explicit and separate treatment of base load and temperature sensitive load, (b) its derivation of the MCF/DD factors used in estimating design year sendout requirements, and (c) an explanation of any judgement factors used in this analysis.

6. That more explicit documentation of the Company's contingency plans in the event of an unforseen cessation of any of its major supplemental supplies be included in the next Forecast.

7. That the Company provide in its next Forecast an evaluation of of a demand management strategy that includes conservation grants and an installation service. The evaluation should discuss the cost-effectiveness of such a strategy to the Company and its ratepayers.

8. That the Company file its Second Long-Range Forecast on July 1, 1982.

9. That the Company arrange a meeting with the Council Staff to discuss the above conditions within 30 days of this decision.

Robert T. Smart, Jr.

Robert T. Smart, Jr., Esq.
Hearing Officer

On the Decision:
Steven Buchsbaum

This Decision was approved unanimously by the Energy Facilities Siting Council at its meeting on March 8, 1982 by those members present and voting. Voting in favor: Margaret St. Clair, George Kariotis (by designee), John Bewick (by designee), Eileen Schell (by designee), Dennis J. Brennan, George Wislocki, Richard Croteau.

Abstaining: Harit Majmudar, Ganson Taggart.

March 15 1982
Date

M. N. St. Clair
Margaret N. St. Clair
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of the Fitchburg Gas and Electric Company for the Approval of a Long-Range Forecast of Electric Needs and Requirements	EFSC No. 81-11B

FINAL DECISION

Paul T. Gilrain, Esq.
Hearing Officer
April 1, 1982

On the Decision:
Margaret Keane

The Council hereby <u>APPROVES CONDITIONALLY</u> the Second Long-Range Forecast of Electric Needs and Requirements of the Fitchburg Gas and Electric Company, subject to the Conditions affixed herein at page 16.

I. History of the Proceedings

Fitchburg filed its Second Long-Range Forecast of Electric Power Needs and Requirements on June 1, 1981. After publication and posting of the notice of adjudicatory proceedings on this supplement, the prehearing conference in this matter was held on October 13, 1981 at Council offices. There were no intervenors in these proceedings.

On October 23, 1981, preliminary discovery questions were sent to Fitchburg to serve as a basis of discussion for a technical session which was held on November 3, 1981 at Council offices. As a result of this technical session, at which the Company evidenced a willingness to work with the Council in improving its forecast, it was decided by the Hearing Officer that an adjudicatory hearing was unnecessary. On November 5, 1981, a revised set of discovery questions was issued for formal response. A procedural order sent with the discovery questions required response by December 4, 1981. Responses were received by the Council on January 6, 1982.

A. Background

Fitchburg Gas & Electric is an investor owned utility which provides electric service to the City of Fitchburg and to the Towns of Ashby, Townsend and Lunenburg. The forecasted sales for 1981, 409.3 million kWh, consists of 57% industrial sales, 23% residential sales, 10% commercial sales, and the remaining 10% is allocated among company use, streetlighting and losses.

The Company's 1981 Supplement is subject to review criteria as stated in EFSC Rule 62.9 (2)(a), (b) and (c), which call for 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 electric 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 its assumptions, judgements and data will forecast what is most likely to occur. The Council applies these criteria on a case-by-case basis.[1]

The Council expects all companies to devote a relatively equal proportion of their resources to forecasting needs and requirements; however, in light of the relative size of the Company, the Council does not require the level of sophistication and detail that it would expect from some of the other, larger Companies. (See attached table) Both the size of the Company's service territory and its heavy industrial load make the Company highly vulnerable to changing economic conditions and migration patterns, in turn complicating the forecasting process. The Council has taken such factors into account in reviewing the Company's forecast.

Prior to 1979, the Company's forecast methodology was characterized by a judgemental approach.[2] In 1978, the Council suspended the adjudicatory proceeding in EFSC 78-11B in order to allow the Company to upgrade its forecast methodology. The methodology used by the Company

1 For a more complete discussion of this criteria see In Re NEGEA, 6 DOMSC ___, EFSC 79-4 (1981) and in Re Boston Gas Co. etal; 7 DOMSC ___; EFSC No. 81-25.

2 In Re NEGEA, id.

Table 1

Fitchburg Gas & Electric Company

A Comparison of Fitchburg G & E with Other Massachusetts Regulated Electric Utilities

Category	Total mWh	Residential Customers
Average MMWEC member	102,716	6,220
Average Total Requirements Co.	64,889	3,807
Average Investor Owned Utility	4,844,974	293,473
Fitchburg	369,055	19,743
Taunton Municipal Light	415,000	20,561

NOTES:

1) MMWEC figures are based on an average of 32 companies. Figures are based on 1979 data.
2) Total requirements figures are based on an average of 8 companies. Figures are based on 1979 data.
3) Investor owned utility figures are based on 6 companies (Eastern Utilities, NEES, WMECo, BECo, CommElectric and Fitchburg. Figures based on 1981 edition of Statistics of Privately Owned Electric Utilities.

improved measurably in 1979. 4 DOMSC 124, 126-130. With this methodology, customer classes were disaggregated, judgements were explained in a more detailed and systematic (i.e., reviewable) manner and the Company set forth plans for a more comprehensive and organized data collection program.

The Company's 1981 Forecast methodology is similar to that used in the Third Supplement submitted in 1979, although additional progress has been made. Fitchburg bases its forecast largely upon an interview methodology that, given the size of its service territory, is appropriate. The Company has standardized the industrial interview format and has made attempts to maintain contacts with the same individuals wherever possible. The Company lists "typical sources of information that are contacted," as opposed to "will be contacted," as stated in the 1979 Supplement.[3] Some of these sources are local public officials, the planning board, builders, developers, bankers, NEPOOL and the Chamber of Commerce, among others.[4]

The Company also conducted an appliance saturation survey, which will be discussed in the analysis of the residential demand forecast.

With these two exceptions, the 1981 Forecast methodology is basically the same methodology, albeit with some increased documentation, as that used in the 1979 Supplement. However, the Company's 10 year peak demand forecast has declined on the order of 15.5 mW from the 1979 Supplement. (See attached graphs.) Given Fitchburg's relatively small peak load (67.5 mW peak in 1980), this amounts to an 18.17%

3 Fitchburg Gas and Electric Light Company, 2nd Long-Range Forecast, June 31, 1981, Appendix B, page 1. ("Forecast")

4 ibid.

decrease from the projection presented in the 1979 filing, certainly a significant and measurable difference. As the methodologies that generated these disparate figures are so similar the question of reviewability enters the case. It is assumed that this change in peak load forecast was based on the Company's judgement and on improved data used in the 1981 filing. In the future, the Company should thoroughly document the basis for any such substantive changes in its demand forecast.

II. DEMAND ANALYSIS

A. Residential

The residential forecast is based on 1977 service territory population estimates adjusted for preliminary population estimates from the 1980 U.S. Census, adjusted growth rates from the Montachussett Regional Planning Commission (as suggested in EFSC 79-11B, 4 DOMSC 124) and the Fitchburg Planning Office.

As a result of these estimates, the Company expects to see increases in one and two person households, forecasting an average annual increase of 100 homes. The Company projects a decline in persons per meter from 3.22 in 1970 to 2.83 in 1995, "projected at a slightly declining rate to reflect growth in smaller number of persons per meter,"[5] based on information from the Montachussett Regional Planning Commission.

In 1980, the Company conducted an appliance saturation study, based on a sample of customers who visited the Fitchburg Gas & Electric Booth at the Fitchburg Home Show. This constituted a 1% sample. The resultant data had significant flaws, which the Company adjusted using

5 Forecast, supra, at 14.

judgemental correction factors, which appear plausible to the Council.[6] The saturation study, while unscientific, does represent a "first step in a long march", and is an excellent example of an appropriate low-cost method. The Company is to be commended for this initiative and ordered herein to progressively continue this approach. See No. 1, infra at 16.

Based on this appliance saturation data, Edison Electric Institute data and appliance replacement rates,[7] the Company forecasted a constant annual load loss of .032 million kWh through 1991 due to replacement of existing appliances with more energy efficient appliances. While the Council is aware that development of service territory specific usage data is an expensive and time consuming proposition, the Company's reliance on the national average use figures generated by the Edison Electric Institute is an area of concern. The Company is urged to look into alternate sources, including figures used by companies whose service territories exhibit similar economic and demographic patterns,[8] and to explore low-cost methods of improving its own residential data base. A post card type survey, in the form of a bill stuffer insert, is one avenue the Company might explore.

The Company, acting realistically in light of data constraints, chose not to attempt to quantify the impact of the Energy Conservation Service Audit Program in this filing. The Company foresees a possible

---

6 A 59% saturation for gas dryers was reported, however approximately 50% of customers do not use gas. This was adjusted to 35%, Water heater saturation were adjusted to equal number of water heater rate customers.

7 Information Request 81-11B, 2

8 The Company is encouraged to look at data utilized by the Massachusetts Electric Company and New England Electric System.

savings of between 20,000-40,000 kWh annually and states that the effect on the forecast for this year "would be in the rounding of the last significant figure in the residential forecast"[9] The Company goes on to say that, "This (conservation impact) will be addressed in future supplements when more information is available."[10]

B, Commercial

The Company's commercial load is largely comprised of multiple housing units. Growth is forecast by assuming average annual usage of 3,929 kWh/residential meter multiplied by an estimated annual average of 68 new meters. This growth projection is based upon 1977 data from the Montachusset Regional Planning Commission and preliminary estimates from the 1980 U.S. Census.

Contribution to peak demand are forecasted by calculating known adjustments to existing commercial and small municipal users, with known use in 1982 as the base year. The growth projections of a constant annual .40 kW summer and a .45 kW winter increase in per customer contribution to peak are somewhat judgemental, but consistent with Montachusset Regional Planning Commission population projections. The Company has also taken notice of factors such as the Proposition 2 1/2 related closing of three schools.

While the commercial forecast methodology is not as precise as might be desired, the Company does have an adequate knowledge of the components of commercial demand in its service territory. Additionally, while further model development in this sector would be desirable, the Council realizes that the commercial sector constitutes only 10% of

9 Forecast, supra at p. 14.
10 id. p. 15

total load in a very small service territory. Nonetheless, the Council expects the Company to continue to develop its data collection and forecasting ability in this area consistent with the prudent investment of its resources.

C. Industrial

The Company states, "the industrial energy forecast is based on known new industrial load, the projected development of the privately owned Montachusset Industrial Park and growth in present industrial customers and the local planning entities."[11] Between 1981 and 1984, the Company expects to see an increase in new industrial load on the order of 8,625 kW, based on contracts or other firm commitments of the Montachusset Industrial Park. Thereinafter, the Company expects to see average annual additions of 1,000 kW due to the Industrial Park. Overall, the Company forecasts a fairly consistant growth pattern averaging about 6.8% annually. Although significant, this projection is lower than the 1979 projection.

As previously mentioned, the Company uses an interview methodology and is moving toward a more systematic data base. The Company is aware of new customers, customer mortality and the general impact of macroeconomic conditions on its various industrial users. Given Fitchburg's large industrial load (58%), such knowledge is essential and the Company is to be praised for the progress it has made in this direction.

However, calculations of underlying average growth, as in other

11 Forecast, supra at 15

sectors, are highly judgemental. Given that the Company does have data generated by its survey, the Company could better quantify its figures, particularly in the areas of conservation, load management and overall macroeconomic impact, by including more of the survey's output in the forecast.

D. Peak Load Forecast

Contributions to peak were derived from projected new loads, using coincidence factors from a study by United Engineers and Constructors.[12] These figures were added to existing summer and winter peaks; NEPOOL peak transmission losses were added to these figures to arrive at the peak load forecast for summer and winter. This method is entirely acceptable to the Council, but it requests, as in the Council's next prior Decision and Order concerning Fitchburg (79-11B), that the Company continue to study and better document the industrial sector's impact on system load.[13]

E. Summary and Conclusions: Demand Analysis

The Company's forecasting efforts have exhibited a substantial improvement since the initial filing in 1976. The Council is aware that, given the nature and size of the Company, informed judgement will continue to be an integral part of the Company's forecasting effort. At the same time the Council wishes to emphasize the importance of fresh data in a judgementally-based forecast, as judgement is ultimately based on data. The Company does not have the option, at this time, of falling

12 Appendix AA
13 4 DOMSC 124, at 146 EFSC No. 79-33 at 22 (1980).

back on sophisticated statistical methodologies and it is imperative that the Company have current data on which to base its judgements. This is of particular importance in the industrial sector, with so much emphasis placed on load necessitated by new construction. More reliable data would lead to a more reliable demand forecast, which is imperative in light of the Company's supply constraints, which will be discussed presently. See Conditions 1 and 2, infra at 16.

III. SUPPLY FORECAST

The Company states, "Planning today is complicated by the long lead times (12 or more years) required to place large base load units into service and the uncertainty of loads and operating conditions that far into the future."[14] This statement is appropriate in the Massachusetts supply planning picture with respect to the uncertainties surrounding new construction. It also reinforces the role of long range supply planning in efforts to minimize these inevitable uncertainties.

The Council is fully aware of the limitations of small utilities in initiating new facilities[15] Within these limitations, however, the Company is obligated to explore all avenues open to it.

The termination of the Company's 40 mW contract with Boston Edison in 1986 will result in a decrease in forecasted reserve capacity from 31.7 mW to 17.2 mW. With the loss of Pilgrim 2, this margin decreases to 15.01 mW. This amounts to only a 20.7% reserve over projected peak. The Company delineates the option of renewing the 40 mW BECo contract and presents alternatives to that option for study. The Company fails to consider the possibility that BECo may not offer the option of

---

14 See In Re. Boston Edison, 7 DOMSC ___, EFSC No. 81-12.

15 See In Re Eastern Utilities Associates System, 4 DOMSC 124, December 1, 1980

contract renewal, which is conceivable given the loss of planned Pilgrim II capacity. The Company lists the following as its options:

> "At November 1, 1986, Fitchburg will be short in the order of 25 MW of capacity through 1991.
>
> This can be made up by an extension of this Boston Edison Contract. However, several alternatives are being explored before making a further commitment.
>
> Several low head hydro proposals appear promising to supply power at less cost than the Boston Edison Contract. These are being explored and discussions are continuing.
>
> Other possibilities include the gas expander turbine proposal which is still under study.
>
> Making our combustion turbine into a combined cycle plant also is another option.
>
> To the extent that any of these, or other possibilities not now known, economically make up our deficiency, they could replace any or all of the capacity which would be offset by the extension of this Boston Edison Contract."[16]

The Company is to be commended for its active pursuit of low head hydro sites (EFSC No. 81-11B 16) and is urged to continue this effort.

However, the Company may be unrealistic in its reliance on the Seabrook units for 20% of its capacity needs. The Public Utilities Commission of New Hampshire, the body having regulatory responsibility for the lead partner in the Seabrook venture, Public Service Company of New Hampshire ("PSNH") recently questioned the financial viability of Seabrook Unit No. 2.[17] Most recently, the Nuclear Regulatory Commission Staff has listed Seabrook Unit No. 2 among 18 nuclear plants currently under construction which it deems "unlikely to be completed".[18]

The charts listed as Figures 4 and 5 demonstrate the seriousness of

---

16 EFSC Information Request 81-11B 17

17 See. NHPUC Docket Nos. DR 81-87, No. Order, 15,424, 15,425, pp. 88 (Comparison of percentage completion and projected on line dates between Seabrook Unit II and Millstone Unit 3). and (1982);DR. 82-63, pp. 18-20 (1982).

18 id.

Figure 5

Fitchburg Gas & Electric Light Company
Comparisons of Resources and Requirements
Megawatts (MW)

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
Projected Peak Load	67.5	69.8	73.5	77.2	77.7	79.0	79.9	80.9	81.8	82.7	83.7	84.6
Load Factor	64.8	66.9	67.7	66.4	66.8	66.4	66.3	66.2	66.1	66.1	66.0	65.9
Total Capability	92.3	93.4	93.4	93.4	102.3*	102.3	101.65	82.56	84.76	84.76	84.76	84.76
Reserve	24.8	23.6	20.5	18.8	26.2	23.3	21.75	1.66	2.96	2.06	1.06	0.16
Reserve(%)	36.7	33.8	28.1	25.2	34.4	29.5	27.2	0.02	0.03	0.024	0.01	

0.002

Calculated from Forecast Table E-17, pp. 63-64

* On line date for Seabrook Unit No. 1.

These figures note the absence of Pilgrim II and assume that Seabrook II will be delayed until 1990 or thereafter.

Figure 5

Fitchburg Gas and Electric Light Company's

Load Forecast and Capability Projections

1100

1000

900

800

700

600

500

400

300

200

insufficient capacity

F.G.E.L.C. Supply Plan

100

F.G.E.L.C. Load Forecast

1979 1980 1981 1982 1983 1984 1985 1986 1987 1988

Study Forecast Period

the Company's supply situation. As the Company has no control over the on line dates or completion of the Seabrook units, particularly Unit II or the actions of the Boston Edison Company, it is imperative that the Company have a comprehensive plan to deal with potential supply uncertainties. This is not to imply that the Council is directing the Company to enter into specific agreements at this time; rather, that the Company should develop an adequate plan to address each of the potential supply scenarios during the forecast period.

Conservation and load management, as supply options, are not to be viewed as a panacea, but should be considered integral components of any feasible supply plan. While time-of-use rates as a demand control technique have not been widely accepted, the Company has done an outstanding job of informing its customers of the implications involved with such rates. The Company could use this expertise in informing its customers of the merits of conservation, both as a method of reducing customer bills and in terms of benefits to the system, particularly where efforts or information would result in supressing peak growth but not necessarily energy sales, i.e., load factor improvement. The Company is urged to complete its study of controlled water heater rates and implement such rates. The Company should continue to study and implement load management initiatives as recommended by its Load Management Task Force and the Company should continue to seek out and support development of cogeneration within its service territory.

IV. ORDER AND CONDITIONS

In light of the considerations set out in the above decision, it is now ORDERED that the Second Long-Range Forecast Supplement of the Fitchburg Gas & Electric Company be, and hereby is, APPROVED subject to the following conditions:

1. In light of the Council's extreme concerns about the Company's potential for unacceptable reserve margins, that the Company develop comprehensive supply plans to be implemented in the event that: 1) the 40 MW Boston Edison supply contract is not offered or renewed by BECo, or not accepted by the Company; 2) the start-up of Seabrook Unit No. 1 is delayed until power year 1985/86; 3) Seabrook Unit No. 2 is delayed until 1988; 4) Seabrook Unit No. 2 is not in service at any time during the forecast period. These supply plans shall include assessments of the feasibility of Hydro-Quebec power, New Brunswick capacity, low head hydro, gas turbines, combined cycle plants, and other options, and of entering into contracts with New England utilities other than Boston Edison. It shall also include a discussion of the costs of each of these potential supply options, including the differential involved in purchasing power from NEPOOL and paying NEPOOL deficiency charges. This shall be presented to the Council within 60 days.

2. That documentation of industrial survey data shall be provided in the next EFSC filing. This includes providing verification of all judgements and supporting documentation, which can be provided without violating the confidentiality of the industries surveyed.

3. That the Company actively endeavor to collect and analyze territory and sector specific data, particularly with respect to the demand forecasting methodology for the residential sector. Further, data which assesses the conservation potential and impact, by sectors, should be documented. Given the Company's limited resources, the Council recommends that the Company develop a long-term data collection plan and implement it in planned, low-cost phases.

4. That the Company continue to encourage development of all cost-effective low-head hydro sites and to actively and aggressively support development of cogeneration and other small power producers. These efforts are to be documented in the Company's next EFSC filing. (See EFSC Rules 64.5 and 64.6)

Paul T. Gilrain, Esq.
Hearings Officer
April 1, 1982

On the Decision:
Margaret Keane

This Decision was approved by a Unanimous vote of the Energy Facilities Siting Council on April 20, 1982 by those members and their representatives present and voting. Secretary Margaret N. St. Clair, Esq.; Bernice McIntyre, Esq. (for Secretary John A. Bewick); Noel Simpson (for Secretary George Kariotis); Harit Majmudar; and George Wislocki. Ineligible to vote:Dennis Brennan.

April 30, 1982
Date

Margaret N. St. Clair, Esq.
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

Petition of the Holyoke Gas & Electric Department for Approval of the Second Long-Range Gas Forecast	)	EFSC No. 81-23

FINAL DECISION

The Energy Facilities Siting Council hereby APPROVES the Second Long Range Forecast of the Holyoke Gas and Electric Department (hereinafter "Holyoke" or "the Department"), subject to the conditions set out in this Order.

Holyoke filed its forecast on August 11, 1981. Staff Information Requests were sent to the Department on December 3, 1981. Answers were received on December 20, 1981. With the publishing of Notices of Filing and Adjudication on December 31, 1981, and January 2, 1982, all interested persons were informed of their right to intervene and to request a hearing. Upon receiving no such requests, and there being no proposed facilities in this forecast, the principals agreed to dispense with an adjudicatory hearing on this matter.

Analysis

Over the past few years, the quality of Holyoke's forecasting has improved markedly. The commitment and effort is evidenced best by the 1981 Forecast, which is the subject of this Decision and Order. With few notable exceptions, Holyoke has presented a document that satisfies the Council's review criteria as stated in EFSC Rule 62.9(2).

The focus of discussion in this Decision is the Department's compliance with three of the four Conditions to the Council's Order regarding Holyoke's last forecast, EFSC No. 80-23. The fourth condition, concerning the Department's procedures for evaluating and improving the energy efficiency of its gas heating conversion customers was sufficiently addressed in Holyoke's forecast and does not require further discussions.

(1) In response to the Council's request that the Department "discuss the rationale for its methodology" used for deriving design degree day standards, Holyoke changed its methodology. Decision No. 80-23 suggested that the coldest period experienced serve as a basis for Holyoke's design degree day standards rather than the previously used averaging process. The Department's present methodology follows that suggestion. The coldest day in the last 26 years serves as the basis for the Department's design day (68 degree days). Similarly, the design year is based on a summation of the coldest heating season experienced in the past 26 years and the coldest non-heating season experienced during that period.

Although this new methodology is directly responsive to Decision No. 80-23, the Council believes that Holyoke may have overreacted to the most recent EFSC Order. In selecting the design year methodology described, the Department is effectively planning for a split year that has never occurred. In fact, the design year forecast of 7322 degree days is almost 5% colder than the coldest split year experienced in the last 26 years (6985 DD in 1969-70).

The staff, concerned with the Council's statutory mandate "to provide a necessary energy supply for the Commonwealth...

at the lowest possible cost" (164 MGLA section 69H), inquired about this apparent overplanning in one of its information requests. The Department's answer reiterated the "coldest historical period" standard and stated that the ability to supply its customer in a design year of 7322 DD would enable it to "meet any contingencies that may arise during the coldest winter or summer period in the future". This is undoubtedly true. However, long range planning involves a delicate balance between the security of future supply and its cost. A review of the design year methodologies used by the 14 gas companies in Massachusetts that file this information with the Council reveals Holyoke's to be the most conservative. As such, this Order is conditioned on the Department either changing its design year methodology to reflect the coldest historical split year actually experienced in a given time period (e.g., past 25 years) or explaining in detail the justification for Holyoke's belief that a more conservative methodology is warranted for its service territory. Although no one can predict with accuracy the severity of future meteorological patterns, given the relatively large deviation by the Department's design year methodology from general industry practice, the Council feels that this condition is appropriate. A list of Massachusetts gas companies' design year methodologies can be provided upon request.

(2a) The second condition to EFSC No. 80-23 requested a more thorough analysis of conservation, including influencing factors, likely effects and bases for conclusions. Section II of the Department's Forecast contains a discussion of the "many behavioral changes" of its customers. However, as admitted on page 4 of that section, the actual degree to which consumer conservation is responsible for and will continue to be responsible for changes in sendout "is difficult to predict". The Forecast contains a trend line analysis that projects the experienced changes in sendout from the 1979-80 heating season to the 1980-81 heating season into the future forecast years. This methodology is explained in Section IV of the Forecast and basically assumes a correlation between new customer hook-ups and increased gas usage per customer per degree day. A note to Exhibit C explains that the 0.5 MCF increase in base use per customer was due to 250 new customers, "many using gas to heat hot water". This explanation, although of the type that distinguishes well thought out forecasts, neither goes far enough nor seems accurate enough to form the basis of a sound methodology. Form G-2 indicates a loss of 564 residential, non-heating customers in the past year. This combined with the high number of residential heating customers lost due to fires (as set out in Holyoke's response to Information Request No. 3) raises an important question as to how many of the customers that converted to gas heat were already being served by gas. The effect of the relative prices of other fuels on a customer's conservation efforts seems quite important as regards conversion customers, whereas the relavent price comparisons for established gas heating customers are the annual changes in the Department's gas tariffs and cost of gas adjustment changes.

To follow up on the excellent beginning that the Department has taken, the Council would like to see developed and documented a residential conservation forecast that takes into account the price of gas, both in terms of annual percentage increases, as regards predicted conservation by established residential gas heating customers, and in comparison to other residential space heating fuels (i.e., oil and electricity) for the purpose of predicting conservation by conversion customers.

The Council understands that intense Congressional activity in the area of natural gas prices is expected during the present legislative session. As such, the Department will need to present its conservation predictions in terms of low-middle-high gas price scenarios. For example, three possible scenarios are: (1) no change in the existing decontrol law. (Natural Gas Policy Act of 1978); (2) the present position of the Interstate Natural Gas Association of America-phase out of new gas controls over three year period from 1983-1986, phase out of old gas controls over five year period from 1983-1988 and a ceiling price of 70% of the refiners' acquisition price; and (3) the present position of the American Petroleum Institute - all gas controls, including old gas, phased out by January 1, 1985. The Department might also consider the effect of a Federal Government order that gas producers rengotiate indefinite price escalator clauses in existing contracts. While we understand that a study of this type may be burdensome for a small company like Holyoke, the Council believes that the impacts of decontrol on the Massachusetts gas industry are, or ought to be, of general concern to all Massachusetts gas companies and their representatives. To this extent, steps to further cooperative studies between companies are strongly encouraged.

(2b) It is a given that in order for Holyoke to present conservation forecast analyses that distinquish between conversion and existing customers, it must have accurate data on which of its customers use gas heat and which do not. This basic knowledge has been awaiting computer availability and training. In its response to EFSC Information Request No. 4, regarding the status of Holyoke's computer capability, the Department responded that computer segregation of heating and non-heating customers "should be available" for the 1982 Gas Forecast Supplement. The Council will condition its approval of this Forecast on the availability of this information by the next filing. If necessary, the Council would prefer to wait an extra month or two before receiving the 1982 Forecast Supplement, rather than have the Department continue to submit estimates based on seven year old survey results.

(3) The final EFSC 80-23 condition to be addressed concerns Holyoke's planning criteria for periods of cold weather that are "longer than a day but shorter than a heating season". The Department's response referred to its Form G-23, which describes a comparison of resources and requirements for peak

day sendout, and included a lengthy narrative detailing its three supplemental supply sources: its interconnections with Bay State Gas Company; its LNG satellite plant and its propane air plant. This discussion was quite helpful and is to be commended. As such, the Council would like to see this type of narrative included in all future forecasts. To avoid duplicative effort, the Department need only address itself to changes in the status of its ability to respond to these "design month" criteria. This coming year's filing, for example, should at a minimum: (1) detail the status and/or results of the Department's contract negotiations with Bay State; (2) update the usage history of the Bay State interconnections to include the flows experienced during the winter of 1981-82; (3) describe Holyoke's LNG purchase experiences during the 1981-82 winter; and (4) describe Holyoke's propane purchase experiences during the 1981-82 winter (now that the Department has 3 propane suppliers).

Overall, the work of the Holyoke Gas & Electric Department has been exemplary. Improved methodologies, greater narrative explanations and specific supply planning changes have all contributed to a Forecast that is "appropriate, reviewable and reliable". The Council notes its appreciation of and satisfaction with the Department's planning process and looks forward to continued cooperation in the future.

ORDER

Given the foregoing considerations and comments, it is now ORDERED that the Second Gas Company Long Range Forecast submitted by Holyoke Gas and Electric Department be APPROVED subject to the conditions noted herein.

Lawrence W. Plitch, Esq.
Hearing Officer

This Decision was approved unanimously by the Energy Facilities Siting Council at its meeting on March 8, 1982 by those members present and voting. Voting in favor: Margaret St. Clair, George Kariotis (by Noel Simpson), John Bewick (by Bernice McIntyre), Eileen Schell (by Richard Pierce), Dennis J. Brennan, George Wislocki, Richard Croteau.

Ineligible to vote: Harit Majmudar, Ganson Taggart.

3-8-82
Date

Margaret N. St. Clair
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

Petition of the Town of Wakefield Municipal Light Department for Approval of the Second Gas Company Long Range Forecast	)	EFSC No. 81-2

FINAL DECISION

The Energy Facilities Siting Council, for the reasons stated below, hereby conditionally APPROVES Wakefield Municipal Light Department's (hereafter "Department" or "Wakefield") Second Gas Company Long Range Forecast.

The Department is unique in that is an all-requirements customer of Boston Gas Company. Wakefield has no direct pipeline supply of its own, nor does it maintain any storage or peaking facilities. As a result, Wakefield's total company sendout constitutes a part of the Boston Gas forecast (Tables G-3(A) and G-24), the most recent of which (EFSC No. 80-25) is concurrently being reviewed by the Council. As such, the Council determined in EFSC No. 79-2 that Wakefield need only file a "narrative" forecast each year. This filing must consist of: (1) the Department's expectations for continuation of its Boston Gas contract; (2) comments on the accuracy and adequacy of Boston Gas' supply figures; (3) a discussion of the role and effect of conservation in the Department's service territory; and (4) an explanation of how the Department plans for and meets its peak day and design year requirements. In this way, the Council has been able to eliminate some regulatory redundancy.

Wakefield submitted its Second Gas Company Long Range Forecast on August 26, 1981. This forecast consisted of a "narrative filing" addressing the several points outlined above. No new facilities were proposed. This filing was supplemented on October 24, 1981, by a set of daily readouts of Boston Gas' meters at Wakefield's four takepoints. On November 4, 1981, the Staff sent the Department a letter containing several information requests, the answers to which were received on November 23, 1981.

Notice of filing was appropriately published in two newspapers of general circulation in Wakefield's service area during three consecutive weeks in December, 1981. There being no petitions to intervene, it was decided to adjudicate this Forecast without a formal hearing. The resulting Decision and Order will address each of the Department's four required points of discussion.

Analysis

(1) Since the last Council decision Wakefield has entered into a new supply contract with its only source of natural gas, Boston Gas Company. The new contract, signed on November 14, 1980, extends the relationship between the two companies until September 1, 1990. As a result, Wakefield's forecast has improved over the previous filing insofar as the Department now shows a firm source of supply through the entire forecast period.

The contract provides for Boston Gas to supply Wakefield's "total requirements of gas", subject to curtailment only in the event that Boston Gas is curtailing deliveries to its own retail firm customers. The amount of gas Wakefield is permitted to take without penalty is limited on both a daily and an annual basis.

During the first contract year (November 24, 1980 - November 23, 1981), the limits were 3,000 MCF per day (assuming 61 degree days) and 315 MMCF per year. These quantities are subject to adjustment for normal weather. In subsequent years, Wakefield is entitled to take an additional 5% of the prior year's sales (both annually and daily). This potential growth for the Department has been inhibited, however. Wakefield has been unable to sign up new gas heating customers due to a clause in the Boston Gas contract. That clause prohibits the Department from accepting new load in its service territory as long as Boston Gas is not accepting new load within its territory, and Boston Gas is only just now beginning to ease a moratorium on new gas hookups that it has imposed since January, 1981. Consequently, in an environment where Wakefield is receiving scores of requests for gas heat conversions, the Department'sforecast for future sendout is a direct function of the quantity and hook-up restrictions in the Department's Boston Gas contract.

(2) The original impetus for the requirement that Wakefield comment on the supply figures submitted by Boston Gas derived from a situation where the forecasts simultaneously submitted by the Department and Boston Gas one year were not in agreement. This concern, however, was not an issue in the present forecast period. Upon review by Wakefield of Boston Gas Company's Second Long-Range Gas Forecast, the Department notified the Council of its general concurrence with the Wakefield-related supply figures. In its "narrative filing", the Department Manager, William J. Wallace,

states "I have studied tables G-3 and G-24 of the recent filing by Boston Gas and feel that if we have normal heating and non-heating seasons, then the supply as indicated will be adequate." In response to a staff inquiry concerning the unspoken contingency in the quoted statement, i.e., a design year, Mr. Wallace was reassuring. In his response of November 18, 1981, he states:

> "We are allowed, under the present contract, to purchase approximately 330 MMCF of gas for the 1981-82 contract year which in essence could be construed as our design for this year. If this should happen, we will have absolutely no problem handling it."

Of course the bottom line is that, short of curtailments of Boston Gas' retail firm customer due to an inadequate supply of its gas, all of the Department's gas needs will be met, regardless of the severity of the winter. As such, the Council and staff can satisfy themselves as to the adequacy of Wakefield's gas supply by assuring that Boston Gas' supplies are sufficient for the forecast period.

(3) Much of Wakefield's narrative filing concerned the Council's third Condition, i.e., the Department's perceptions of the role and effect of conservation efforts in its service territory. It is Mr. Wallace's view that with the exception of extremely cold weather, his customers have experienced a conservation rate of 2% this past year. Little if any conservation was noticed during "extremely cold" heating months. The Manager went on to say that on an MCF/degree-day basis, "my non-heating customer did very little, if any, conservation, but my heating customers on an overall basis conserved in the neighborhood of 3 to 4%. These numbers appear

quite reasonable to the Council and, combined with the Department's expected gas heating conversions in the next few years make up a reasonable, reviewable and accurate forecast.

(4) Finally, the Department is required to explain how it "plans for and meets its peak day ... and design year requirements". In this regard, the Department has not adequately responded. Although the constraints of the Boston Gas supply contract place obvious limits on the flexibility available to Wakefield, the Council expects to see as much planning as is reasonable within those constraints.

Both in its filing and in its response to staff information requests, Wakefield equated its peak day and design year planning to its contractual limits. As noted earlier, for example, Mr. Wallace construed his allowed annual supply for this contract year to be his company's design year.

The Council would prefer to see Wakefield perform independent calculations of anticipated peak day and design year requirements for its predicted number of heating and non-heating customers for each of the five forecast years. Along with those calculations, an explanation of the methodology used to perform these predictions and the rationale for choosing said methodology should be submitted. Only in this way can the Council make an independent evaluation of the adequacy of Wakefield's supply contract with Boston Gas. Upon request, Council staff would be glad to provide typical methodologies used by other gas companies in the Commonwealth.

The Council notes its appreciation of and satisfaction with the Department's overall efforts and looks forward to continued cooperation in the future.

ORDER

Given the foregoing considerations and comments, it is now ORDERED that the Second Gas Company Long Range Forecast as submitted by Wakefield Municipal Light Department be APPROVED subject to the condition noted in paragraph (4) above. The four points of discussion set out in EFSC No. 79-2 as continuing guidelines for Wakefield's "narrative filings" are hereby reaffirmed.

Lawrence W. Plitch, Esq.
Hearing Officer

This Decision was approved unanimously by the Energy Facitilies Siting Council at its meeting on March 8, 1982 by those members present and voting. Voting in favor: Margaret St. Clair, George Kariotis (by Noel Simpson), John Bewick (by Bernice McIntyre), Eileen Schell (by Richard Pierce), Dennis J. Brennan, George Wislocki, Richard Croteau.
Ineligible to vote: Harit Majmudar, Ganson Taggart.

3-8-82
Date

Margaret St. Clair
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of the Massachusetts Electric, New England Power, Yankee Atomic Electric and Manchester Electric Companies for Approval of a Second Long-Range Forecast of Electric Power Needs and Requirements	)	EFSC No. 81-24

FINAL DECISION

Paul T. Gilrain, Esq.
Hearing Officer
March 31, 1982

On the Decision:
Martha Stukas
Ron Lanoue
John P. Hughes

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of the Massachusetts Electric, New England Power, Yankee Atomic Electric and Manchester Electric Companies for Approval of a Second Long-Range Forecast of Electric Power Needs and Requirements	EFSC No. 81-24

The Energy Facilities Siting Council hereby APPROVES the Second Long-Range Forecast of Electric Power Needs and Requirements as submitted jointly by the Massachusetts Electric, New England Power, Yankee Atomic Electric and Manchester Electric Companies (hereinafter "Companies" or "NEES").[1]

---

1 For convenience , the petitioning Companies are referred to throughout this decision as the "Companies" or "NEES". For reference and the sake of clarity, the following paragraphs describe each company and its relationship to NEES.

Massachusetts Electric Company provides retail service for customers in Massachusetts only and is a wholly-owned subsidiary of New England Electric System (NEES). All of Massachusetts Electric Company's bulk power needs are provided by New England Power Company (NEPCo), which is also a wholly-owned subsidiary of NEES.

NEPCo is a bulk power supply company and provides generation and most of the major transmission facilities for all the NEES retail companies. These companies include, besides Massachusetts Electric Company, the Narragansett Electric Company in Rhode Island and the Granite State Electric Company in New Hampshire. NEPCo also serves, at wholesale, a number of municipal and other small utility systems, plus a few large industrial customers.

(footnote 1 continued on next page)

I. Introduction and History of the Proceedings

A. Introduction

In its 1981 filing, the Companies continue the progressive, evolutionary development of their demand forecasting and supply planning capabilities which was first evidenced in the 1980 forecast filing. (See: 5 DOMSC 97, 98-100 (February 3, 1981)). That filing was unconditionally approved. The Companies' approach to demand forecasting is noteworthy for their insightful commitment of resources to both quality data and innovative methodologies. It is precisely this balance that ensures Council confidence in the reliability of a forecast in the present, highly uncertain planning environment. The Companies' supply

---

1 (continued)

Yankee Atomic Electric Company (YAEC) owns and operates a 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. NEPCo owns 30% of the stock of YAEC and receives 30% of its output. The plant in Rowe is a base-load unit which is run at practically constant power level, depending on the unit's ability. Information provided by YAEC is Total Electric Energy Requirements and Agreements for electric service. The Rowe Plant is included in the list of existing generating units (See: NEES Forecast, Vol. 2).

Manchester Electric Company is an independent company which services the town of Manchester, Massachusetts. Manchester Electric Company receives all of its bulk power needs from New England Power Company and thus makes its Council filings jointly with Massachsuetts Electric Company.

All 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 NEPOOL Forecast for New England 1976-1985, and supplements thereto, as filed with the Council by the NEPOOL planning staff. (See: NEES Forecast, Vol. 2, Appendix A). The operation of these facilities, once placed in service, is placed under the control of the NEPOOL dispatch center, the New England Power Exchange (NEPEX).

planning initiatives are similarly balanced in that the Companies' emphasis on risk minimization is critical where, as now, risks are many and expensive.[2]

In the Decision that follows, the Council separately analyzes the demand forecast and the supply plan. The Demand Analysis comments on the forecast methodologies and the data resources for total power requirements in three major customer classes: Residential, Commercial, and Industrial. (*See* Table I). The ensuing Supply Analysis addresses the Companies' plans for supplying electricity to meet their customers' projected needs.

B. History of the Proceedings

The Companies filed their Second Joint Long-Range Forecast on May 1, 1981. By Order of the Hearings Officer on August 13, 1981, the Companies gave notice of an Adjudicatory Proceeding to the cities and towns pursuant to Council regulations and subsequently published notices in newspapers to the same effect, and a pre-hearing conference was held at the Council offices on September 15, 1981. There were no motions to intervene or participate as a "participating party", and, by agreement with the Companies, a desk review was conducted. Numerous Technical Sessions were conducted and information requests were sent to and answered by the Companies in order for the Staff to compile a sufficient record upon which to base this decision.

---

2 The Council notes the emphasis in NEES' supply planning efforts on non-capital intensive technologies, a highly appropriate reaction to today's historically unprecedented costs of capital.

Table 1

New England Electric System

Summary Statistics

KWH Forecast (in millions of kWh)

	Actual 1980	Forecast 1985	Forecast 1990	Average Annual Change
Residential				
MECo		4367	4596	
Narra		1358	1399	
GS		246	293	
NEES	5930	5971	6288	.06%
Commercial				
MECo		3971	4605	
Narra		1390	1505	
GS		181	210	
NEES	4908	5542	6320	2.6%
Industrial				
MECo		3322	3946	
Narra		845	976	
GS		53	76	
NEES		4221	4997	
NEPCo Industrial		34	34	
NEES	4066	4255	5031	2.1%
Total NEES	14904	15768	17639	1.7%

Class KWH as a Percent of Total kWh

	1980	1985	1990
Residential	39.7%	37.8%	35.6%
Commercial	32.9%	35.1%	35.8%
Industrial	27.2%	27.0%	28.5%

Source: NEES Second Long-Range Forecast.

II. Demand Analysis

A. Introduction and General Method

The Council unconditionally approved the NEES Companies' 1980 Supplement to its Long- Range Forecast. In the decision, we offered several suggestions to NEES in an effort to further refine the Companies' relatively progressive methods in forecasting their electric power needs and requirements. The majority of these suggestions were directed towards encouraging the Companies to improve their documentation of the forecast and in data collection at the service-territory level. The Companies satisfactorily have addressed each of the Council's suggestions in the present filing.

The analysis of the current Forecast will focus predominantly on important incremental changes made since the previous filing. The reviewability of the current Forecast is substantially improved in comparison to previous filings. Both the clarity of the forecast narrative and supplementary materials provided through Technical Sessions and information responses have facilitated this review. The Staff has appreciated the cooperation of NEES staff during these Technical Sessions and would especially like to thank the Companies for providing three volumes of documentation, indexed chronologically and by category, for each of the sectoral models presented in the Forecast.

The Companies have followed through on several plans to remedy the few problem areas of the 1980 filing. As mentioned above, forecast documentation has been greatly enhanced. More importantly, NEES staff have begun several projects to collect territory-specific data and to refine sectoral models which use this data. We realize that the results of data collection efforts are not immediately visible, since adequate time-series analysis requires many years' experience, by definition. Further sophistication of the model must always be preceded by the accumulation of data to support the model.

In general, NEES continues to forecast long-run trends in electric power consumption using a computer-based model of its service territory. This model uses national and regional econometric models to project the general economic performance of its service area. The inputs which drive these models are projections and assumptions concerning the future prices of electricity and of substitute fuels, population trends, conservation factors, the impact of load management, alternative energy sources, and building design practices. A separate forecast is generated for each sector or class of service. The methodology for forecasting the sales of each sector is discussed below.

B. Residential Forecast

The Companies forecast growth in residential energy (kWh) consumption by use of an "end-use" model based on 21 distinct end-uses.[3] The Companies first projected the number of potential users or dwelling units by dividing a population forecast by trends in household size for each year in the forecast period. Average use per appliance and the

---

3 Appliances specifically identified by the model as having a significant contribution to residential load are: frost-free refrigerators, standard refrigerators, frost-free freezers, standard freezers, dishwashers, electric range, microwave oven, room air-conditioning, central air conditioning, washers, electric dryers, uncontrolled electric hot water heaters, controlled hot water heaters, solar-assisted hot water heaters, unsupplemented electric heat, solar-assisted heat, electric heat and wood stoves, fossil auxiliaries, color televisions, black and white televisions, lighting, and miscellaneous.

saturation (appliances per household) of each appliance were forecast. The product of the number of dwelling units, appliance saturation, and use per appliance, yielded total kWh use attributable to each appliance category. Finally, these totals were summed across all 21 appliance groups to determine total forecasted residential kWh consumption.

1. Number of Customers

The Companies' 1980 Forecast of the number of customer or dwelling units was based on the arithmetic mean of the population forecasts provided by two sources. In that earlier forecast, NEES averaged the population estimates derived from the models of Chase Econometrics Associates, Inc. ("Chase") and the National Planning Associates ("NPA"). Adjustments were made to the Chase population projections as a result of the Companies' judgement that the model underestimated population by projecting excessive net out-migration. In our last decision, we took exception to the way in which this model was applied to the NEES service territory, since the Chase model was used without migration adjustments for the projections of employment, a significant explanatory variable in the NEES commercial and industrial forecasts. In addition to this lack of internal consistency, we also noted that both the Chase and NPA models reflected national and regional trends in population which may not accurately reflect trends in the NEES service territory. As a result, the Council urged NEES to improve the internal consistency of the relevant parts of the forecast and to collect and analyze more territory-specific data in population and employment forecasts. 5 DOMSC 97, 104 (Feb. 13, 1981).

In the 1981 filing, the Companies have responded to the Council's concerns by using only the Chase model to forecast state population, with alterations which reflect the Companies' judgement regarding net migration. Use of the Chase population forecast is consistent with the income and employment forecasts used subsequently in the model. These state population forecasts were then used to estimate NEES service area population over the forecast period. Each city served by NEES was identified and an analysis of population by city was performed. Whereas previous filings relied on county data for the forecast of service area population, the 1981 filing used current (1980) U.S. Census data by city. The historical percentage of the population of each state served by NEES[4] was determined, and this percentage was then applied to the Chase forecasts. State household estimates were derived by dividing aggregate state population by household size estimates. The Companies assumed that household size in the states served by NEES would exhibit the same trends as estimated for the nation by the Census Bureau.

In response to the Council's suggestion in the 1980 Order, NEES investigated the possibility of developing a territory-specific population model. However, since the Companies operate in three New England States, use of a regional model was deemed preferable. As an alternative, NEES is in the process of developing the computer ability to simulate state scenarios with the Chase model. This capability should greatly enhance the reliability of the forecast by alleviating the need to extrapolate from national trends.

2. Appliance Saturations

The Companies based their forecast of applicance saturations in large part on periodical surveys of a sample of NEES residential

4 NEES provides electric service in parts of Massachusetts, Rhode Island and New Hampshire.

customers. The most recent residential survey was conducted in 1978.[5] Customer accounting records, the NEPOOL Model, and in-house estimates of dwelling units, were also inputs into the appliance saturation forecasts.

Consistent with the 1980 filing, the Companies categorized the major appliances into four groups: competitive necessity, non-competitive necessity, competitive luxury, and non-competitive luxury. Appliances were categorized on the basis of the degree of competition among fuels in the use of these appliances, and on the strength of demand by households for these items. The Companies then developed a matrix to illustrate the theoretical foundation for the categorization of appliances, as depicted in Figure 1.

The appliance matrix is divided into four quadrants. The first quadrant ("I") is comprised of necessary, non-luxury items, where all dwelling units in the NEES service area are assumed to contain at least one of each appliance in this quandrant. Since there is no competition among fuels which serve these appliances, electricity has a 100% market share.

5 The Companies' 1982 residential survey is in progress.

Figure 1.

New England Electric System

Appliance Saturation Matrix[6]

	Competition	No Competition
	II	I
Necessity	Water Heating Home Heating Cooking	Refrigerator Lighting TV Washers
	III	IV
Luxury	Dryers	Dishwashers Air Conditioning Freezers Microwave Ovens

6 Source: NEES Second Long-Range Forecast, Figures B-3, B-4.

Quadrant II contains necessary, non-luxury appliances for which there is fuel competition. Although all primary dwelling units are assumed to contain at least one of each item, the decision for choice of appliance by fuel type is hypothesized to be a function of several explanatory variables, including primary heat source, annual operating cost, installation cost, availability of fuel source, and geographical area.[7]

Quandrant III contains only one appliance. This matrix identifies the clothes dryer as a luxury appliance for which there is fuel competition. The forecast of saturation levels for this appliance must reflect a dual-step consumer choice problem: first, the decision to own or not to own a clothes dryer must be explained; and, second, the choice of fuel type, conditional to appliance ownership, must be predicted. The variables which were suggested to explain the saturation of clothes dryers include: ownership of a clothes washer, family size, type of housing, primary heat source, and operating cost.[8]

Appliances which were grouped in Quadrant IV consist of non-competitive luxury items. Electricity is projected to have 100% of the market share for these appliances. The decision for ownership is assumed to be related to annual income, annual operating cost, family size, type of primary heating system, space availability, structural requirements (i.e., wiring), and age of house.

The forecasted saturation levels of appliances within each category were either fixed at levels based on the survey data,[9] determined by functions specified from survey data,[10] based on NEPOOL Model results,[11]

---

7 Forecast p. II-22 (Figure B-4)
8 Forecast p. II-22 (Figure B-4)
9 Refrigerators, washers, lighting
10 Dryers, air conditioners, water heating, space heating
11 Televisions, microwave ovens

dependent on other economic and demographic variables,[12] or computed by a new competitive appliance submodel.[13]

The Companies have responded to the Council's suggestion to test additional explanatory variables for significance in explaining the saturation levels of various appliances, as requested in our decision on the 1980 filing. 5 DOMSC p. 106. For example, the equations which were used to forecast the saturation levels of dishwashers and freezers in the 1980 filing were criticized for their reliance on disposable income as the sole explanatory variable. According to the Companies' appliance saturation matrix, both of these appliances are categorized as non-competitive luxuries (i.e., Quandrant IV). Since electricity has 100% of the market share in the use of these appliances, the task is to forecast the aggregate future ownership of these items, as opposed to estimating ownership by fuel type. In the 1981 Forecast, the ownership decision in this category is theoretically based on at least eight factors, including disposable income.

In its decision on the 1980 Forecast, the Council noted that the Companies' workpapers indicated the significance of variables such as family size, age of housing, and household type in explaining the saturations of dishwashers and freezers. 5 DOMSC p. 106. This apparent significance is consistent with a priori expectations regarding the relevance of these factors in predicting consumer choice to purchase these appliances. In the 1981 Forecast, the Companies have tested alternative specifications which examined the impact of family size and household type on the ownership of these appliances. Modifications have

12 Dishwashers, freezers
13 Electric ranges, dryers, space heating

been made to the previous functional forms where statistical significance was established. Table 2 provides summary statistics of selected equations.

In some instances, the Companies appeared to have had an insufficient number of observations to produce conclusive results on appliance ownership. This seems to be the case in the explanation of freezer saturation by type of dwelling unit, where data is available for only the most recent residential survey (See: Table 3 and 4). As noted earlier, the eventual accumulation of time-series data should help to alleviate this constraint.

The 1981 Forecast contains a much improved theoretical and methodological basis for forecasting the saturation of appliances for which fuel competition exists. These appliances consist of space and water heating systems, as well as the percentage of electric ranges and dryers in non-electrically heated homes.

Residential space heating is a necessity for which fuel competition clearly exists, i.e., a Quadrant II appliance. According to the Companies' matrix theory, the decision for ownership of Quadrant II appliances by fuel type is assumed to be generally dependent on primary heat source, annual operating cost, installation cost, availability of fuel source, and geographical area. In forecasting the penetration rate of electric space heating, it was assumed that future saturation levels would be a function of the following factors:

"1) the future price of electricity, natural gas, and No. 2 home heating oil,
2) the efficiency and relative initial costs of alternative heating systems,
3) the level of informational marketing and tax incentives offered by the government and energy suppliers on:
    a. heat pumps
    b. heat storage/time-of-use rates

Table 2

New England Electric System

Residential Sector Forecast

Summary of Results of Dishwasher and Freezer Saturation

Equations Estimated by Ordinary Least Squares[14]

1981 Forecast

Dependent Variable	Company	R^2	Mean	S.E.E.	F-Ratio[15]	T Value
Saturation of Freezers (Income)	NEES	.94	21.9	2.2	76	8.7
Saturation of Dishwashers (Income)	NEES	.99	40.1	2.57	2369	48.7

1980 Forecast

	Company	R^2	S.E.E.	F-Ratio[16]
Sat. Freezers	MECo	.98	0.6	374
	Narr	.96	0.8	172
Sat. Dishwashers	MECo	.91	3.0	75
	Narr	.89	3.1	55

14 NEES Second Long-Range Forecast, Figure B-5.
15 All F-Ratios significant at the 1 percent level.
16 All F-Ratios significant at the 1 percent level.

Source: Residential Model Documentation Volume.

Table 3

New England Electric System

Residential Sector

Food Freezer Appliance Saturation Rates[17]

	Family Size	Saturation
	1	6.1%
	2	15.3
	3	21.0
	4	25.9
	5	30.7
	6	34.0
	7	38.1
	8	45.8
	9	61.5
Average	3.07	20.3%

17 Source: NEES Second Long-Range Forecast, Figure B-6.

Table 4

New England Electric System

Residential Sector Forecast

Food Freezers Saturation Rate by Type of Dwelling[18]

Year	Single Family	Multi-Family	Total
1972	NA	NA	NA
1975	NA	NA	NA
1978	27.4	7.5	20.2

18 Source: NEES Second Long-Range Forecast, Figure B-7.

c. solar assisted systems
4) Customer's perception of the importance of:
a. fuel availability
b. convenience and cleanliness"[19]

Based on the Companies' 1980 customer billing records, the present saturation of electric space heating in their respective service territories are as follows:[20]

Massachusetts Electric	9.25%
Narragansett Electric	6.2%
Granite State Electric	13.6%

The 1981 Forecast assumes that in the short-run, natural gas would be the most economical choice for heating new homes and for conversions. Long-term assumptions are based on the changing dynamics of the energy market, as well as on the non-price factors listed above.

The forecasted saturation levels for electric space heating were computed by the Companies' competitive appliance submodel. This submodel encompasses assumptions regarding the relative prices of competing fuels resulting from natural gas deregulation, predictions regarding oil price increases, and the impact of conversions of major electric generating plants to coal. The specific price assumptions incorporated into the submodel are summarized in Table 5. In recognition of the inevitable uncertainties of the future energy market, the Companies developed high, medium, and low penetration rate scenarios for electric space heating. This revealed that lower saturation rates for competitive appliances could shift the forecast downward by as much as 0.3 percent.[21] The alternative forecast scenarios were developed by varying the probabilities associated with various possible penetration

19 Forecast p. II-24
20 id, p. II-23
21 id, p. II-116

Table 5

New England Electric System

Price Assumptions in Competitive Appliance Submodel

1980 Annual Owning and Operating Costs Space Heating ($1980)

	Energy Cost[1]	Carrying Cost[5]	Total
Electric Resistance[2]	921	211	1132
Electric Heat Pump[2]			
1.5 COP*	614	633	1247
2.0 COP	460	633	1093
Electric Storage[6]	675	671	1346
Oil Hydronic[3]	845	399	1244
Oil Warm Air[3]	845	352	1197
Gas Hydronic[4]	441	334	775
Gas Warm Air[4]	441	299	740

1990 Annual Owning and Operating Costs Space Heating ($1980)

	Energy Cost[1]	Carrying Cost[1]	Total
Electric Resistance[2]	968	211	1179
Electric Pump[3]			
1.5 COP	645	633	1278
2.0 COP	484	633	1117
Electric Storage	710	671	1381
Oil Hydronic	1030	399	1429
Oil Warm Air	1030	352	1382
Gas Hydronic	867	334	1201
Gas Warm Air	867	299	1166

(Footnotes on next page)

Footnotes to Table 5.

1 2 story 1500 sq.ft. house heat loss 9.0 KW (all fuels) 6,225 degree days.
2 MECo residential rate 5.48cents kWh, fuel adjustment 2.3 cents/kWh included.
3 929 gallons, $1.00/gallon, 55% seasonal efficiency.
4 133.8 mcf heat, 60 cents equivalent/gallon, 60% seasonal efficiency.
5 Mortgage rate 11% for 30 years.
6 Based on new storage rate being developed.
* COP: coefficient of performance.

Source: Figure B-5, Residential Model documentation.

1 Assumes cost rises with inflation.
2 Cost rise .05% above inflation.
3 Assumes cost rises 2% above inflation, 55% seasonal efficiency.
4 Assumes equal in price to oil in 1985 when fully deregulated, and rises 2% over inflation from 1985-1998, 60% seasonal efficiency.
5 Based on incentive rate for electric storage - rising .05% above inflation.

Source: Figure B-6, Residential model documentation rates incorporated in the competitive appliance submodel. These penetration rates, in turn, vary with the availability of natural gas. The penetration rates are then applied to net newly constructed units, i.e., the sum of unit additions and replacements, in a stock adjustment manner. The alternative forecast scenarios are summarized in Table 6.

The competitive appliance submodel was also used to forecast the saturation of electric dryers, ranges, and water heaters in non-electrically heated homes. This submodel is a more systematic approach to forecasting saturation rates for appliances for which fuel competition exists, and the Companies are to be complimented for their work in this area. Future filings would be enhanced by a more rigorous discussion of the development and selection of the probabilities associated with the various penetration rates within the forecast narrative. Additionally, while the Companies are correct in examining the impact of relative energy prices in determining the saturation of major appliances by fuel type in the short-run, the Companies may wish to explore the underlying characteristics[22] of those fuel "commodities" for a long-run approach to the ownership decision. As the relative price differentials diminish, due to gas deregulation, coal conversions, and other factors, customer

---

22 A Consumption - characteristics model hypothesizes consumer "utility" to depend directly on the underlying qualities or characteristics that are "produced" by the consumption of commodities.
See: K. Lancaster [1966], "A New Approach to Consumer Theory," Journal of Political Economy 7 : 132-57 and J. Muellbauer [1974], "Household Production Theory, Quality, and the 'Hedonic Technique'," American Economic Review 64: 977-94.
For a critique of this approach, see:
Pollak, R.A. and M. Wachter [1975], "The Relevance of the Household Production Function and Its Implications for the Allocation of Time," Journal of Political Economy 83: 255-78.

Table 6

New England Electric System

Competitive Fuel System
Alternative Forecast Scenarios

Alternative Scenario Assumptions[23]

Scenario A: Declining competitiveness of electricity within the residential sector.

Scenario B: Accelerated competitiveness of electricity within the residential sector.

Scenario C: All low growth assumptions

Scenario D: All high growth assumptions

Alternative Scenario Forecasts[24]

	Scenario			
	A	B	C	D
Electric Heat Penetration (MECo)	35%	72%	35%	72%
Water Heating Saturation (MECo)	21.8%	25.5%	21.8%	25.5%
Population Growth Rate (MECo)	0.0%	0.0%	(0.9)%	0.5%
Price of Electricity Real Growth Rate	1.5%	1.5%	2.5%	0%
Commercial Growth Rate (MECo)	2.9%	2.9%	0.4%	4.5%
Energy Growth Rate (NEES) (Base Case - 1.8%)	1.7%	2.0%	0.8%	2.8%

23 1981 Forecast p. II-116
24 1981 Forecast p. II-117, Figure G-1.

perception of non-price related qualities of fuels may become increasingly important in the consumer's choice of fuel type and appliance ownership. Experimentation in this type of "characteristics" approach is ripe for future research.

3. Average Use (kWh) per Appliance

In our decision on the 1980 Forecast, the Companies were directed to document the appropriateness of using the NEPOOL model average use per appliance and peak load factors. 5 DOMSC p. 108. The 1981 Forecast again predominantly relies on the NEPOOL model for these estimates. As in previous filings, the Companies stated that the NEPOOL model results are used only when these results are superior to other sources of data, and steps are taken to ensure the reasonableness of applying the results to the NEES service area. The Council remains skeptical of the quality and currency of the NEPOOL data.[25] We note that the NEES Companies have commenced a research study of kWh usage per appliance,[26] and we anticipate that this potentially more reliable data will be incorporated into the forecast when available.

In sum, we find the residential forecast of 0.06% annual growth to be appropriate and supported by available data. The company continues to improve its methodology and data collection with this filing.

C. Commercial Sales Forecast

The commercial sector is comprised of a very heterogeneous mix of customers and an equally diverse variety of end-uses for electricity by

25 See: In Re Boston Edison 7 DOMSC p. ____, EFSC No. 81-12 (February, 1981)

26 NEES Second Long-Range Forecast, Vol. 3, Appendix B.

each customer. This inherent diversity has complicated the process of modelling this sector in the past. Typical commercial accounts include schools, churches, hospitals, and master-metered apartments, food stores, government agencies, and retail and wholesale trade organizations. Each type of customer has unique energy requirements and contributes unevenly to the growth in sales to the class, i.e., many customer types which comprise a significant amount of total class sales may have customer peaks that are noncoincident to either sectoral or system peaks.

The Companies completed the classification of commercial accounts by 2-digit SIC codes in the latter part of 1979. The ability to track kWh sales by SIC code greatly improved the forecasting capability for the sector. As a result, the 1981 filing offered two separate forecasting methodologies which make use of this data. The new data was first used as the theoretical foundation for the development of an econometric model of future kWh sales to the commercial class. Secondly, the Companies also developed a new end-use model for forecasting commercial sales. The following two sections describe these separate, albeit complementary modelling approaches which yield a forecast of 2.6% annual growth.

C.1 Commercial Sector Econometric Model

The Companies' 1979 and 1980 filings forecast commercial sales by use of an econometric model. The 1981 filing rectified two identifiable short-comings in those previous filings. First, the Companies no longer forecast the number of customers and kWh per customer separately. This change improves the reliability of average kWh consumption per customer estimates, since previous methods aggregated the unequal consumption patterns of new and existing customers. Additionally, the data for kWh sales by SIC were used as the theoretical basis for the econometric specification of the model.

Two alternative econometric forecasts were performed in the current filing. In one case, the commercial sector of each of the Companies' distribution subsidiaries was examined as a whole. In the second, sub-categories of identifiable commercial accounts[27] were segregated and forecast separately. These identifiable customer groups comprised approximately 15 percent of total commercial sales. The remaining 85 percent was classified as a general commercial sales and projected in aggregate.

The diversity of commercial customers types and end-uses for electricity has contributed to the limited conceptual validity of previous econometric modelling efforts on the commercial sector, since energy use in this sector is not a simple function of a single, easily-measured level of production, such as GNP or employment. In the past, energy use in this sector had not been disaggregated into various customer groups. The Companies' SIC classification project has now allowed commercial index variables to be developed for each operating company. These variables are a weighted index of demographic,[28] local economic,[29] and national economic[30] factors. Several indices were

27 The sub-categories identified by the Companies from rate schedule data and SIC code data were: Churches, all-electric schools, all-electric nursing homes, supplemental electric space heating, large non-electrically heated schools, large hospitals and the Massachusetts Bay Transportation Authority.

28 Service territory population or dwelling units

29 Real disposable income, non-manufacturing employment

30 GNP

developed for each operating company by experimenting with different combinations of variables and weights. Equations were then estimated by using regression techniques. The resulting forecasted kWh consumption levels for each category were subsequently reduced by an adjustment for conservation, as in the Companies' 1980 filing. These conservation levels by commercial category were based on a study performed by XEnergy, Inc., a consulting firm which provided the data for the Companies' commercial end-use model.[31]

C.2 Commercial Sector End-Use Model

NEES identified the development of a reliable commercial end-use model as a principal objective in June 1979. The current filing is the first forecast produced by the model, and the Companies are to be commended for their progress.

The success of any model must be evaluated according to its objectives. The Companies' stated purpose in developing this commercial end-use model was to "(1) provide an understanding of how commercial customers use electricity; (2) establish a basis for estimating the potential of load management strategies; (3) provide a forecasting structure capable of policy and strategy formation; and (4) provide an alternative to econometric forecasts."[32] The Council approved of the Companies' prudent commitment for resources to the large-scale data collection efforts and methodology refinement necessary to achieve these objectives. Because of this commitment, the Council offers the following observations and suggestions.

31 Final Report on the Development of an Energy End-Use Database for the Commercial Sector Services by the Retail Subsidiaries of the New England Electric System in Rhode Island and Massachusetts. XEnergy, Inc., Burlington, Mass, September 1981.

32 1981 Forecast, p. II-58

The Companies were assisted in the development of this model by XEnergy, Inc. The tasks involved in the development of the model were summarized as follows:[33]

(1) Development of square feet per employee statistics

(2) Development of 1980 floor space inventory of commercial building stock

(3) Derivation of BTU/sq. ft. by end use and SIC group for existing commercial building stock

(4) Estimation of BTU/sq. ft. statistics for 1995 for existing commercial building stock and post-1980 construction

A key element of the end-use model is the floor space inventory of existing commercial building stock. The floor space statistics developed by the XEnergy Report are estimated to have a 95 percent accuracy.[34]

Second, total building energy use statistics were derived from a study of actual fuel bills acquired from energy audits performed by XEnergy in New England, while the allocation of total energy to each end-use was performed according to standard engineering practices. The reliability of these estimates depends on whether the building stock of the XEnergy audit sample is representative of the NEES territory building stock. This is an area of uncertainty which would be alleviated by a more comprehensive commercial class survey. A survey of total energy use and energy by end-use could improve the basis for the Companies' estimates of coincident peak factors for the commercial class, as well.

---

33 XEnergy, loc. cit., p. iii.
34 XEnergy, op. cit., p. iii, p.3

Third, the model is highly sensitive to variations in market shares by end-use. Estimates for air conditioning and space heating exhibit the greatest need for development, since they are major electricity consuming end-uses. In particular, an over-stated market share for electricity in commercial space heating could have contributed to model results which were higher than actual sales. Since air conditioning and space heating use is seasonal it might be more quantifiable by analyzing customer billing records and/or through customer survey data.

The assessment of commercial conservation potential may provide an opportunity for a combination of end-use and econometric modelling. The end-use model analyzed existing building stock for conservation potential on the basis of recommended measures made to customers who received XEnergy Audits. The incentive to conserve was then assessed in relation to business awareness, payback periods, and initial investment expenditures. Analysis of conservation <u>potential</u> on an end-use basis is appropriate and valuable, since the effectiveness of different policies and strategies (such as load management techniques) can be evaluated. However, the conservation <u>incentive</u> needs to be related to decision criteria, as in a "capital budgeting"[35] approach. An econometric model which examines commercial conservation in the context of price expectations, discount rates, and investment lags could be an effective approach to the problem. Finally, further refinement of the model could

35 See William J. Baumol, "Capital Budgeting", Ch. 19 of <u>Economic Theory and Operations Analysis</u>, Prentice Hall, 1972.

be achieved through the addition of more commercial subsectors and through scenarios of new building designs which incorporate greater shares of new technologies and load management strategies.

The Council commends the Companies for their efforts in modelling this increasingly important and often overlooked sector. Future filings would be enhanced by a more detailed explanation of the interaction between the econometric and end-use models of commercial kWh sales.

D. Industrial Sector Forecast

The 1981 Forecast of industrial sales pursues essentially the same methodology which was reviewed in the Companies' previous filing. However, certain modifications have been made to the model which improve both its reviewability and reliability and thus improve the Council's confidence in the forecast of 2.1% annual growth. Historically, the industrial model disaggregated customers into 2-digit Standard Industrial Classification ("SIC") sub-categories. In the current forecast, these sub-categories were subsequently evaluated for adequately representing the product diversity of the SIC group, since individual industries within an industrial group have different levels of intensity of electrical usage. Certain industries[36] were heterogeneous at the 2-digit SIC level and merited further disaggregation. As a response the Companies established profiles of these sub-industries.[37]

Maintenance of industrial sales data on an SIC basis is necessary

36 MECo: SIC's 307, 367, 281, 262, 357, 366, 339, 329, 335, 376; NECo: SIC's 332, 281, 364, 373, 396, 335, 391, 354, 226, 307.

37 These sub-industry profiles tracked "...employment, major products, market orientation, historical electricity usage, (and) energy consumption breakdown for those large industrial firms within the Company's service territory." (p. II-80).

to adequately account for differences between the national and service area industrial mix. It was noted in our last decision that the NEES Companies serve large shares of two industrial groups: SIC 355 (Special Industrial Machinery), and SIC 357 (Office Computing and Accounting Machines), the so-called "high tech" industries. Since the share of these industrial groups in the national and regional economies is lower than their relative share in the NEES territory industrial mix, this implies a dissimilarity in industrial electricity intensity between the NEES area and the national averages. The Companies have alleviated some potential errors resulting from assuming national trends in industrial mix and energy requirements by disaggregating these more important sub-industries to the 3-digit SIC level.

The Council has encouraged the disaggregation of industrial sales into 3-digit categories for the NEES territory in previous decisions. 5 DOMSC p. 113. However, we realize that strict pursuit of this data is costly and, in many instances, provides little additional information relative to the cost of obtaining it. We encourage the Companies to further refine their 3-digit SIC capability for only those SIC groups whose energy requirements are significant in their overall requirements and which are sufficiently heterogeneous to merit the additional data collection, unless the benefits of this data collection clearly outweigh the costs of obtaining it.

Industrial sales were then forecast at the appropriate 2- or 3-digit SIC level by regression equations. Value-added[38] by state, as a measure of industrial output, was the primary explanatory variable in

38 In distinguishing between final and intermediate goods and services value-added is the incremental value of the good at each state of manufacture.

these equations. Table 7 summarizes the functional form and summary statistics of the specification for SIC 35, Non-Electrical Machinery. Final specifications of the regression equations were for 2-digit SIC's included within the forecast, and alternative equation formats were made available to the Staff through Technical Sessions and information requests.

The Companies have responded to the Council's earlier suggestions regarding data collection on and theoretical foundation for industrial price and conservation adjustments. See: 5 DOMSC p. 116. The impact of higher energy prices on industrial usage was grouped into three areas:

> "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."[39]

In the Industrial Sector model, energy was considered to be a "factor of production" or an input into the industrial production function. This method improves the theoretical basis of the Companies' conservation estimates. The first two areas considered the impact of higher prices by holding production constant at a given level of output and varying either the level or combination of energy inputs to produce a given output. The third area examined the impact of higher prices on energy usage by allowing the level of production to vary.

39 Forecast p. II-85

Table 7

New England Electric System

Industrial Sector Forecast: SIC 35: Selected Equations

A. Massachusetts Electric

(1981): El. Sales = -180564 + 5.1305 X U.S. Real Output
(-3.05) (6.29)

CR Sq. = 0.859 F = 74.24 DW = 1.43 Pet. Ser. = 12.52

(1980): El. Sales = -301644 + 1554.92 X U.S. SIC 35 Prod. Index
(-1.24) (8.146)

CR Sq. = .879 F= 66.4 DW = 2.232 SEE 10300
Elast. = 1.182

B. Narragansett Electric

(1981): El. Sales = 63637 + 1187.64 X U.S. FRB Indu. Index
(1.56) (3.35)

- 65684 X Real El. Price
(-3.21)

CR sq. = 0.644 F = 10.95 DW = 1.63 Pet. SEr. - 17.43

(1980): El. Sales = 144608 + 1011.29 X U.S. SIC 35 Prod. Index
(8.77)

- 100605 X NECo real industrical price (-1)
(-18.0)

CR Sq. = .939 F = 46.96 DW = 2.545
Elasticity of Production Index = 1.91
Elasticity of Real Price = 2.6

The efficiency of conservation was hypothesized to be affected by several price and non-price factors;[40] however, the price elasticity estimate was determined to be the most effective measure of the combined impacts of these separate factors. The price variable which the model used was either a five-year (moving) average real price variable or price elasticity factors estimated by the NEPOOL model.

We strongly encourage the Companies to develop this production function framework. [This is a research area in which most utilities could experience gains from trading information and methods.] NEES is in a position to make valuable contributions to the literature in this field, given its forecasting expertise, resources and data. Although the Companies have concentrated on exploring the impacts of higher electricity prices on conservation, the model provides an exceptional opportunity to evaluate the impact of changes in policy variables, as well. For example, the model could be modified to examine the effect of various load management strategies on productive efficiency. Additionally, the Companies should consider testing the significance of the marginal price of electricity on industrial conservation, in addition to the more long-run influence of five-year averages.

Lastly, interfuel substitution as a determinant of industrial kWh sales was considered to depend on the price and availability of competing fuels, technology, and capital. Although no interfuel substitution was explicitly projected in the base case, the forecast did provide scenarios with varying levels of substitution.

---

40 These factors included: "...the price of electricity, the cost of energy-saving alternatives, the availability and cost of money, the supply of energy, the awareness level, etc." 1981 Forecast p. II-85.

E. 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 annual growth of .06% for residential, 2.6% for the commercial sector, 2.1% for the industrial sector, and an overall annual growth rate of 1.7% 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.

III. Supply Analysis

A. Introduction

This review of the New England Electric System companies (NEES) supply situation examines three dimensions of supply. The review is in keeping with the Council's statutory mandate to examine whether the regulated companies long-range forecasts and supply plans can "provide a necessary power supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost." MGL Ch. 164 s. 69H. The adequacy of supply is a company's ability to provide capacity sufficient to meet its loads throughout the forecast period. The diversity of supply measures the mix of energy sources used. Our working principle is that a more diverse supply mix, like a diversified financial portfolio, is less risky. A review of the cost of supply addresses whether the company is minimizing long-run system costs, subject to the constraints of adequacy and diversity.

Table 8

New England Electric System

New England Power Company Generation Mix, 1981-1991

	1982 MW	1982 %	1990 MW	1990 %
Nuclear		8.2		14.9
Yankee plants (total)	383.7	8.2	383.7	7.6
Seabrook Unit 1 & 2 & Millstone Unit 3	-		369.4	7.3
Coal		24.8		32.4
Brayton Point Units 1,2,3	1163.9	24.8	1163.9	23.0
Salem Units 1,2,3, South Street, Mt. Tom	-	-	476.5	9.4
Oil or Diesel		41.7		29.2
Salem Units 1, 2, 3, 4, South Street, Mt. Tom, Brayton Point Unit 4	1386.2	29.5	909.7	17.9
Other base or cycling	442.6	9.4	442.6	8.7
Peaking Units	129.3	2.8	129.3	2.6
Hydro		25.4		23.6
Pumped storage (peaking)	601.6	12.8	601.6	11.9
Conventional (peaking)	592.1	12.6	592.1	11.7
Total	4699.4		5068.8	

NOTE: Table does not include 200 MW of planned cogeneration, hydro, wood, and other capacity intended primarily for energy, not capacity; 72 mW of demand management savings with respect to summer peak; nor planned capacity sales. We also note that data on capacity, while accurate, does not reflect actual energy production. For example, because of the very recent coal conversions at Brayton Point and Salem Harbor, which represent approximately 30% of NEP's capacity, these units may produce between 50 and 60% of NEP's total energy.

Source: Forecast Vol. 2, EFSC Tables E-12, E-14, E-17 (Revised)

B. Adequacy of Supply

As can be discerned from Table 8, (and referring to Table E-17 as revised 10-15-81) the Companies are fully able to meet their capability responsibility during the forecast period. Even with the deletion of the capacity from the already cancelled Pilgrim II power plant and the possible delay or cancellation of Seabrook Unit II, the Companies will be able to meet the needs of their customers. Assuming arguendo Seabrook Unit II is not on line in 1990/91, NEES will still have 4784.5 MW of net capacity available during the summer of 1990, to meet a projected peak load of 3585 MW.[41] This would still leave NEES with a comfortable reserve of 33.5%. The Companies are to be commended for their wisdom in choosing to purchase small increments of capacity from a greater number of large base load plants, thus minimizing the effects of plant outages. Furthermore, they enhance the strength of their supply plan through their efforts to manage demand (i.e., load), rather than merely respond to "natural load growth."

The Companies project 4305 MW of capacity available in the summer of 1982, with an expected reserve margin of 38%. (2nd Forecast, Vol. 2, Table E-17). They forecast that they will maintain a reserve margin with respect to summer system peak of over 29% through the forecast period. Additions of 369 MW of nuclear capacity from the Seabrook I and II and Millstone III projects are planned between 1984-1988 (id.).[42]

41 Forecast Vol. 2, p.22, Table E-17, Summer 1990 as revised 10-15-81 shows 4899 MW of available capacity, including 115 MW from Seabrook Unit 2 and a projected peak load of 3585 MW.

42 The Company does not include as firm capacity an additional planned 200 MW from alternate energy sources, including solid waste, low-head hydro, wood, and wind energy. (Forecast, Vol. 2, pp. 1-2).

However, such capacity is not needed for reliability: the Companies would still have a reserve margin of 26% in the summer of 1990 without these projects. The nuclear capacity should be judged for its contribution to system diversity, oil displacement, and for its effects on system costs[43].

NEES also has plans to manage the growth in the peak load; "(t)hrough major conservation and load management programs, the NEES companies aim to hold peak demand and energy growth to an annual average of no greater than 1.8% and 2.1% respectively" (Forecast, Vol. 2, p. I-2). The companies expect to reduce 1990 summer peak by 72 MW and winter peak by 151 MW through storage heat, controlled water heaters, heat pumps, solar systems, rate reforms, storage cooling, and cogeneration; much greater savings will be realized in later years. (2nd Forecast, Vol. 1, pp. II-109 - II-115). To date, the Companies have monitored storage heat installation, are continuing to install water heater controls, and are studying other suitable options (ibid, pp. II-112-14). In addition, the Companies have begun tests of NEES' patented Two-Way Automated Control System (TWACS), which may be used to control loads during peak periods. (Response to Information Request No. 6, Oct. 9, 1981; SEC Form 10-K, Dec. 31, 1980, p. 7).

---

43 Note that the Companies state in the Forecast: "The availability of the energy from those units is essential to meet the projected load and capacity requirements of the NEES companies and to reduce our dependence on foreign oil." (Forecast, Vol. 2, p. 1). See: <u>In Re MMWEC</u> 5 DOMSC at 89. Need may be predicted on: 1. growth; 2. replacement capacity; 3. oil displacement; 4. improvement of economic mix; or 5. reliability.

As the Companies state: "it should also be understood that load management is dependent on customer reaction and participation, regulatory concurrence, load research results, and future cost trends."(Forecast, Vol. 2, p. II-110). The Council however wishes to note that NEES believes itself capable of responding to these uncertainties, while other companies back away from the management tasks of load control. The Council hopes and expects that NEES will implement the planned load management programs announced in its Forecast where cost effective and prudent. The Council supports NEES' demand strategy, and expects that other firms could profit from the NEES experience.

C. Diversity and Cost of Supply

Diversity in sources of electrical generation is a means of minimizing the vulnerability of a system to interruptions in fuel supplies, and to abrupt increases in the price of any fuel source. The smaller the proportion of generation mix which any one supply source represents, the greater the stability and reliability of the electricity supplies.

C.1 Coal Conversions

NEES was dependent upon oil for just under 75% of its energy supply as late as 1979 (NEESPLAN, First Update, p. III-1). Since that date, NEES has made more progress in reducing its dependence on oil than any other Massachusetts utility. With the conversion to coal of its Brayton Point Units 1-3, the system has halved its oil dependence to 37% of net generation (calculated from Form 10-K, New England Electric System, for the Fiscal Year ended Dec. 31, 1980, p. 6).

The Company has since officially announced plans for the conversion to coal of 3 additional units at Salem Harbor[44]. Based on 1980 net generation, these conversions could reduce system oil dependence still further to only 26% of kilowatt-hours produced.

The Companies plan to rely on a mix of sources for coal supplies in order to minimize the chance of disruption in this fuel supply. It will buy coal from various suppliers in 3 separate coal producing areas of the Northeast; the coal can be shipped via several different rail systems to 5 ports. The NEES Companies have built and are using a coal-carrying barge for water transport to their plants and have also laid the keel for an ocean-going, self-unloading collier. (Form 10-K, p.11; NEESPLAN First Update, part V).

We note that the Companies have recently begun the process of converting three of its units at the Salem Harbor Station to coal. As was the case with the Brayton Point conversion, this conversion will be accomplished in an environmentally accpetable manner. The conversion will, in addition to reducing the cost of power to NEES' customers, increase the life of the three units.

The Council endorses the coal conversion plans of the Companies. The Companies and their customers are benefiting from the shift away

---

44 The conversion of Salem Units 1, 2 and 3 was begun on March 1, 1982 under a delayed compliance order from the Environmental Protection Agency. Conversion and environmental compliance should be complete by late 1985.

from costly oil imports to more reliable and less expensive domestic coal; the Companies have also shown sensitivity to environmental concerns. The Companies are the coal conversion leaders of the Commonwealth, if not the country.

C.2 Nuclear, Oil, and Hydroelectric Initiatives

The Companies have purchased shares in the planned Millstone 3 and Seabrook nuclear projects. These additions to capacity will increase the System's reliance on nuclear-generated electricity from 11% in 1980 to over 20% at the end of the forecast period (Calculated from Form 10-K, p.6, and Forecast, Vol. 2, Tables E-12 to E-15). This new capacity will provide a more diverse generation mix vis-a-vis the use of oil; it is expected to be less costly than the oil generation it would displace.[45]

NEES has formed a subsidiary to engage in domestic oil exploration. It is expected to produce the equivalent of 1.8 million barrels of oil for system use in 1981, which would amount to approximately one fifth of its projected 1982 oil consumption (Form 10-K, p.11, Forecast Vol.2, p.23, and EFSC calculations). Whether this effort would insure that the Companies' obtained a reliable increment of oil supply during a foreign oil emergency would however depend upon what fuel oil allocation scheme would be decided upon by Federal and state authorities; this increment of energy supply is not fully secure, though certainly more secure than imported oil.

The Companies are part of a NEPOOL consortium that is pursuing the importation of Canadian hydroelectricity. Although contracts have not

45 We are however seriously concerned over the status of Seabrook Unit No. 2 See N.H. PUC Docket DR 81-87 (1982) at 120;

been signed and approved by the regulatory authorities of both countries, negotiations have progressed to the point where NEES has announced its intent in filings before the N.H.P.U.C. to license the transmission tie to Quebec. Canadian power would provide a significant increment to the New England supply mix, though the Canadian policy of pricing such power near to the avoided costs of the purchasers means cost savings will be small.

C.3 Alternative Energy Supplies

These "traditional" diversification plans involving coal, nuclear, oil and hydro are supplemented by a relatively unique set of plans to develop renewable energy sources and to manage demand for electricity. NEES was one of the first utilities in the country to pursue a "least-cost" supply strategy (and one of the first to do so without being so ordered by regulators).

The Companies plan to obtain 200 mW of generating capacity from alternative energy sources in the period 1981-1996. This would include 90 MW from solid waste, 30 MW from low-head hydro, 20 MW from wood, and 10 MW of wind power (2nd Forecast, Vol.2, pp.1-2).

At present the Companies have under contract 39 MW of capacity from the Refuse Fuels, Inc. and the Massachusetts Refusetech Inc. trash-to-energy plants. They are to be in operation in the mid 1980's. The Companies are negotiating with other solid waste projects, though none have refuse contracts sufficient for operation (Responses to Information Requests 18, Oct. 9, and 18(a) and (b), November 20, 1981).

The Companies have purchased approximately 17 MW from the Lawrence (Massachusetts) hydroelectric facility, and have signed agreements with three other projects. Negotiations are underway with over 20 other developers. (Response to Information Request 16, November 20). Progress, however, has been slow because the high cost of money has made many efforts prohibitively expensive. The Companies have a contract with Windfarm Industries for an estimated 100 MWH of energy from a wind farm in W. Brookfield, Massachusetts. (2nd Forecast, Vol.2, Table E-24). The facility is viewed as an experiment by the Companies. NEES also has underway a feasibility study for a 15 MW wood-burning cogeneration plant in Erving, Massachusetts, a joint venture with E.G.& G.. The Companies also offer technical assistance to so-called PURPA Sec. 201 small power producers, dealing with interconnection and rates. They have entered agreements with four potential cogenerators (Responses to Information Requests 15a, Oct. 9, and 15b, Nov. 20, 1981).

The Council believes that the Companies may be able to increase their efforts to promote cogeneration subject to cost-effectiveness criteria and the existence of appropriate client industries. The Companies forecast 19 MW of cogeneration capacity will be added by 1990 and they are investigating additional potential for cogeneration (Forecast, Vol.1, Table F-1 and Response to Information Request 14, Oct. 9). In contrast, an intensive effort by Northeast Utilities (N.U.) identified an estimated 200 MW of "economically developable" cogeneration in that system's Connecticut service territory, which N.U. expects to see 100 MW installed by 1987. N.U. is considering a variety of service and incentive programs to realize this potential. (EFSC 81-17, Northeast Utilities Conservation Program for the 1980's and 1990's, pp.73-4). The Council recognizes that the N.U. and NEES service territories are substantially different. Nevertheless, the Council encourages NEES to investigate more actively its cogeneration potential, and to consider additional joint ventures with industry or demonstration projects (possibly including new technologies such as fluidized bed coal combustion and district heating).

On balance, the Companies are clearly leaders in their plans to develop renewable technologies. However, the Council recognizes that such technologies are no panacea. As the Company notes, present "(p)reliminary analyses indicate that the overall cost of utilizing alternative energy sources is as high or higher than exercising options with conventional energy conversion techniques." (2nd Forecast, Vol. 2, p.3). Nevertheless, costs and technologies may shift during the next decade. The Companies' plans are such that the plans will allow the system to gain significant expertise in each technology which it can exploit should conditions warrant further investment. The NEES renewable energy program is a model for other Commonwealth utilities. The Council anticipates that the Companies will soon place some of the 200 MW target into the category of firm plans.

C.4 Demand Management

The Companies have also announced plans to manage the demand for their product. NEES describes these plans as "a concerted load management and conservation program" (Form 10-K, p. 7) aimed at holding growth in energy and peak power to preestablished levels. The Companies have several load management research projects underway and have plans for their implementation. They describe their conservation plans as involving "consumer education, energy audits, and the promotion of conservation programs." (2nd Forecast, Vol. 1, p. II-4).

The Companies have offered several such conservation programs to date. The MECo subsidiary provides a program of 15% grants for conservation measures in electrically heated homes.[46] NEES has also conducted energy management seminars for large commercial and industrial customers; provided pamphlets and literature; tested a commercial and industrial audit program; and distributed several small energy-saving devices (New England Electric, Load Management and Conservation Monitoring Report, Nov. 1980, pp. 21-35).

The Companies have conducted a major study of their commercial sector energy use and are now formulating plans to sell energy management services in this market (XEnergy, Inc. Final Report on the Development of an Energy End Use Data Base for the Commercial Sector Serviced by the Retail Subsidiaries of the New England Electric System, September 1981; NEESPLAN First Update, pp. VIII-6-7). The commercial sector may be the largest source of cost-effective energy savings. The NEES commercial sector study found existing commercial buildings could reduce energy use for lighting by one tenth to one half, for space heating by perhaps a tenth (XEnergy, op cit, Task 5, p. 15). This sector is also the fastest growth sector in the NEES territory; though it presently uses 30% of the system's output, it is expected to account for 50% of the gain in load between 1981 and 1990 (Calculated from Forecast, Vol. 3, Table E-8). The Companies' progress in this sector will be a most significant part of their supply planning strategy; the Council awaits the Company's actions and results.

46 The Council and the Executive Office of Energy Resources indicated their endorsement of this program, and of recovery of its cost by the Company, in testimony before the Department of Public Utilities (DPU 800; Massachusetts Electric Co.). The recovery was allowed, DPU 800, pp. 33-34 (1982).

D. Conclusions: Supply Plan

The Council APPROVES unconditionally the NEES supply plan. The Council wholeheartedly endorses the intent of the Companies to minimize their capital requirements through a least-cost strategy that bridges traditional utility planning, renewable energy sources, and management of energy demand. The Companies have an opportunity for several years to experiment with conservation and load management to determine the effectiveness and prudence of these strategies for their system. They must gain experience today if their supply planning goals are to become a reality tomorrow. If such strategies can be managed effectively, the Companies might be able to back out of additional high cost,conventional generation, and postpone the construction of new power plants for a number of years.

The Companies' strategy has yet to be fully tested - their plans are in the early stages of development, and growth in demand does not presently require urgent action. The Council would like the Company to press ahead in exploiting these opportunties for both the System and for other similarly situated utilities in the Commonwealth. In that regard, it should be noted that the program requires concurrence and endorsement from other regulatory bodies, principally the Department of Public Utilities, if NEES is to be able to minimize long-term costs for its ratepayers.

IV. Conclusion

In summation, there is not much reason for the Council to alter the conclusion stated by the Council in its last Decision and Order that: "The breadth and depth of each of [NEES'] supply initiatives establish new standards for the power industry in the Commonwealth and, in aggregate, make major contributions in support of Federal and State oil backout policies." (5 DOMSC, EFSC 80-24, February 13, 1981, pp. 118-119). The Company has achieved more to date in diversifying its energy supply mix, and in reducing costs to its ratepayers, than has any other utility in the Commonwealth.

The Council also stated in its last forecast it "enthusiastically approves the NEES Supply Plan on the assumption that the Companies will act to implement the load management and conservation proposals contained in the Plan. In addition, the Council expects that the Companies will demonstrate actual load management and conservation improvements in future filings". (Id., p. 124). The NEES initiatives are only beginning to become the "concerted" and "major" effort as described by the Company. The Council hopes to see the Company's plans blossom into realized actions in its future forecast filings.

V. Decision and Order

The Second Long-Range Forecast of Electric Power Needs and Requirements as submitted jointly by the Massachusetts Electric, New England Power, Yankee Atomic Electric, and Manchester Electric Companies is hereby APPROVED without conditions.

Energy Facilities Siting Council

Paul T. Gilrain, Esq.
Hearing Officer
April 1, 1982

On the Decision:
Martha Stukas
Ronald A. Lanoue
John Hughes

This Decision was approved by a unanimous vote of the Energy Facilities Siting Council on April 20, 1982 by those members and representatives present and voting: Chairperson Margaret N. St. Clair, Esq.; Bernice McIntyre, Esq. (for Secretary John A. Bewick); Noel Simpson (for Secretary George Kariotis); Harit Majmudar; and George Wislocki. Ineligible to vote; Dennis Brennan.

Date

Margaret N. St. Clair, Esq.
Chairperson